BEFORE THE

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF THE BOARD OF DIRECTORS FOR UTILITIES OF THE DEPARTMENT OF PUBLIC UTILITIES OF THE CITY OF INDIANAPOLIS, AS SUCCESSOR TRUSTEE OF A PUBLIC CHARITABLE TRUST, FOR APPROVAL OF GAS COST ADJUSTMENTS TO BE APPLICABLE IN THE MONTHS OF DECEMBER 2023, JANUARY AND FEBRUARY 2024	)	**CAUSE NO. 37399-GCA 160**

Petition for Approval of Gas Cost Adjustments To Be Applicable in the Months of December 2023, January and February 2024

Cause No. 37399 – GCA 160

Prefiled Direct Testimony and Attachments

John F. Lamb

Filed
October 2, 2023

TABLE OF CONTENTS

TABLE OF CONTENTS

Tab 1

BEFORE THE

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF THE BOARD OF DIRECTORS FOR	**)**
UTILITIES OF THE DEPARTMENT OF PUBLIC	**)**
UTILITIES OF THE CITY OF INDIANAPOLIS,	**)**
AS SUCCESSOR TRUSTEE OF A PUBLIC	**) CAUSE NO. 37399-GCA 160**
CHARITABLE TRUST, FOR APPROVAL OF	**)**
GAS COST ADJUSTMENTS TO BE APPLICABLE	**)**
IN THE MONTHS OF DECEMER 2023, JANUARY	**)**
AND FEBRUARY 2024	**)**

<u>PETITION</u>

<u>TO THE INDIANA UTILITY REGULATORY COMMISSION:</u>

The Board of Directors for Utilities of the Department of Public Utilities of the City of Indianapolis, as Successor Trustee of a Public Charitable Trust, d/b/a Citizens Gas (hereinafter referred to as "Petitioner"), respectfully represents and shows the Commission:

<u>Petitioner's Characteristics and Other Matters</u>

1. Petitioner is subject to the jurisdiction of the Commission in the manner and to the extent provided by the laws of the State of Indiana, including certain sections of the Public Service Commission Act, as amended. Petitioner's rates and charges and terms and conditions for gas service are subject to the approval of this Commission by virtue of the provisions of IC 8-1-11.1-3(c)(9). Petitioner's principal office is at 2020 North Meridian Street, Indianapolis, Indiana 46202.

2. Petitioner is authorized to and is engaged in rendering gas utility service in Marion County, Indiana. It owns, operates, manages and controls plant and equipment, used and useful for the distribution and furnishing of service to the public. Petitioner takes delivery of its supplies of natural gas from Panhandle Eastern Pipe Line Company ("Panhandle"), Texas Gas

Transmission Corporation ("Texas Gas"), Midwestern Gas Transmission (“Midwestern”) and Rockies Express Pipeline (“REX Pipeline”).

3. The books and records of Petitioner supporting the data, calculations and allegations contained in this Petition are available for inspection and review by the Commission and the Indiana Office of Utility Consumer Counselor.

4. The names and addresses of the persons authorized to accept service of papers in this proceeding are:

John F. Lamb
Manager, Regulatory Affairs
Citizens Energy Group
2020 North Meridian Street
Indianapolis, Indiana 46202-1306

Scott Franson (Attorney No. 27839-49)
Citizens Energy Group
2020 North Meridian Street
Indianapolis, Indiana 46202-1306

Steven W. Krohne (Attorney No. 20969-49)
Ice Miller LLP
One American Square, Suite 2900
Indianapolis, Indiana 46282-0200

Request for Approval of Gas Cost Adjustments
to be Applicable During the Months of December 2023, January and February 2024

5. This Petition is an application under IC 8-1-2-42(g) for Commission approval of Petitioner's gas cost adjustments to be applicable for the December 2023, January and February 2024 billing months. This Petition is filed in accordance with the Public Service Commission Act, as amended, and in compliance with the Commission's May 14, 1986 Order in Cause No. 37091, the Commission's December 11, 2002 Order in Cause No. 41605, the Order in Cause No. 37399-GCA75 and the Commission's August 27, 2014 Order in Cause No. 44374. Pursuant to the Stipulation and Settlement Agreement on Gas Cost Adjustment Modification Issue ("Stipulation"), approved by final Order of the Commission in Cause No. 37399-GCA75 on December 4, 2002, as such Stipulation has been thereafter amended; the resulting monthly GCA factors attached as Attachment JFL-1 are subject to change.

6. Copies of Petitioner's proposed monthly tariff sheets incorporating its gas cost adjustments in each Rider A, are attached as Attachment JFL-1. The bill impact statements are attached as Attachment JFL-2.

7. Petitioner's cost of gas, based upon the estimated average gas cost for the three months of December 2023, January and February 2024, is estimated to total $62,670,008. Petitioner's requested gas cost adjustment rates are set forth in the following Rider A (One-Hundred Forty-Seventh Revised Page No. 501, One-Hundred Forty-Eighth Revised Page No. 501, and One-Hundred Forty-Ninth Revised Page No. 501) and will be applied to all bills rendered by Petitioner during its December 2023, January and February 2024 billing months. Supporting schedules containing estimated cost data relating to the requested gas cost adjustment rates are set forth in Attachment JFL-3.

8. Petitioner has made every reasonable effort to acquire long-term gas supplies so as to provide gas to its retail customers at the lowest gas cost reasonably possible. Changes in Petitioner's gas cost since its last base rate proceeding in Cause No. 43975 reflect changes in natural gas purchases and the rates of its pipeline suppliers, which have been filed with the Federal Energy Regulatory Commission.

WHEREFORE, Petitioner respectfully prays that the Indiana Utility Regulatory Commission, as provided for in Indiana Code §8-1-2-42(g)(1), conduct a summary hearing on the matters set forth herein and thereafter enter an Order in a timely manner in this Cause:

(a) approving Petitioner's proposed monthly tariff sheets, *i.e.*, Rider A One-Hundred Forty-Seventh Revised Page No. 501, One-Hundred Forty-Eighth Revised Page No. 501, and One-Hundred Forty-Ninth Revised Page No. 501, as are attached to this Petition;

(b) authorizing and approving the monthly gas cost adjustments set forth in each Rider A (identified as Attachment JFL-1), and in the supporting schedules attached to this Petition, to become effective for Petitioner's December 2023, January and February 2024 billing months;

(c) making such further orders and providing such further relief as may be appropriate and proper.

DATED this 2nd day of October 2023.

BOARD OF DIRECTORS FOR UTILITIES OF THE DEPARTMENT OF PUBLIC UTILITIES OF THE CITY OF INDIANAPOLIS, AS SUCCESSOR TRUSTEE OF A PUBLIC CHARITABLE TRUST

By: ______________________________

Joseph M. Sutherland
Vice President, Regulatory & External Affairs
Citizens Energy Group
2020 North Meridian Street
Indianapolis, Indiana 46202
(317) 927-4522

ATTEST:

____

Craig L. Jackson
Senior Vice President and
Chief Financial Officer

STATE OF INDIANA)
) SS:
COUNTY OF MARION)

VERIFICATION

I, Joseph Sutherland, being first duly sworn upon my oath, hereby affirm that I am a Vice President of the Board of Directors for Utilities of the Department of Public Utilities of the City of Indianapolis, as Successor Trustee of a Public Charitable Trust, Petitioner in the foregoing Petition, and that in such capacity I have reviewed the above and foregoing "Petition" and that the matters contained therein are true and correct to the best of my knowledge, information and belief.

Joseph M. Sutherland

Subscribed and sworn to before me a Notary Public in and for said County and State this 2nd day of October 2023.

MARY RETT KEANE
Notary Public, State of Indiana
Johnson County
Commission Number NP0666545
My Commission Expires
April 12, 2031

Notary Public
Printed Signature: Mary Rett Keane
Resident of Johnson County

My Commission Expires:

April 12, 2031

CERTIFICATE OF SERVICE

I hereby certify that on the 2nd day of October 2023, I served a copy of the foregoing Petition upon the Office of Utility Consumer Counselor by delivery or by personal delivery, pre-paid First Class United States mail or electronic mail on the following:

Office of Utility Consumer Counselor
115 West Washington Street
Suite 1500 South
Indianapolis IN 46204
infomgt@oucc.in.gov

Steven W. Krohne (Attorney No. 20969-49)
Ice Miller LLP
One American Square, Suite 2900
Indianapolis, Indiana 46282-0200
(317) 236-2494
E-Mail: steven.krohne@icemiller.com

Scott Franson, (Attorney No. 27839-49)
Citizens Energy Group
2020 N. Meridian Street
Indianapolis, IN 46202
Telephone/Fax: (317) 927-4307
E-Mail: SFranson@citizensenergygoup.com

Attorneys for Petitioner,
Citizens Gas

Tab 2

INTRODUCTION

Q1. PLEASE STATE YOUR NAME.

A1. John F. Lamb.

Q2. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A2. I am employed by the Board of Directors for Utilities of the Department of Public Utilities of the City of Indianapolis (the "Board") which does business as Citizens Energy Group ("Citizens"). The Board is the successor trustee of a public charitable trust and, manages and controls a number of businesses, including the gas utility doing business as Citizens Gas ("Citizens Gas" or "Petitioner"). Since January 2014, I have held the position of Manager, Rates and Business Applications.

Q3. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A3. I hold a Bachelor of Science degree with a major in Accounting from Purdue University and a Master of Business Administration degree with a concentration in Accounting from Indiana Wesleyan University.

Q4. PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND AND EXPERIENCE.

A4. Prior to joining the Citizens Regulatory Affairs department, I was a Senior Accountant in the Citizens Accounting Department since 2011. In that capacity, my work focused on gas accounting, monitoring capital projects, and preparation of the annual report filed with the Indiana Utility Regulatory Commission ("IURC" or "Commission").

Q5. PLEASE DESCRIBE THE DUTIES AND RESPONSIBILITIES OF YOUR PRESENT POSITION.

A5. As Manager of Rates and Business Applications, I am responsible for the implementation and administration of Citizens Energy Group's regulated utilities' rates and charges. Since 2014, I have been responsible for the preparation of GCA changes and other miscellaneous rate matters.

Q6. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION ON BEHALF OF CITIZENS?

A6. Yes.

Q7. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A7. The purpose of my testimony is to describe the tariff sheets and supporting schedules reflecting the gas cost adjustments that Citizens Gas proposes become effective for the months of December 2023, January and February 2024. My testimony also discusses Citizens Gas' projection period, reconciliation period and the Monthly Price Update. Additionally, I describe Citizens Gas' supply portfolio, and provide evidence concerning the gas supply sources and firm gas supply contracts used by Citizens Gas to meet its customers' requirements. I also provide testimony on demand and supply planning activities, the prepaid gas program, the Citizens Gas hedging program, and any changes to the load forecast.

<u>GAS COST FACTOR CALCULATIONS</u>

EXHIBITS AND SCHEDULES

Q8. PLEASE DESCRIBE EXHIBIT NO. 2.

A8. Exhibit No. 2 is my direct testimony.

Q9. PLEASE PROVIDE A BRIEF EXPLANATION OF ATTACHMENTS

JFL-1 THROUGH JFL - 3.

A9. Attachment JFL-1 is Petitioner's GCA tariff sheet (Rider A), for the periods December 2023, January and February 2024. The rates shown on each Rider A are the result of all appropriate estimations and reconciliations, as previously authorized by the Commission. Attachment JFL-2 shows the impact of the proposed GCA rates on a residential heating customer's bill at 5, 10, 15, 20 and 25 dekatherms, compared to currently effective rates – i.e. October 2023 – and compared to the GCA rates in effect one year ago.

Attachment JFL-3 consists of all schedules required in support of the GCA rates shown in Attachment JFL-1. These schedules were prepared in a manner consistent with Petitioner's prior GCA filings and incorporate the changes approved on May 14, 1986 in Cause No. 37091. The schedules also are in compliance with the changes approved on August 31, 2011 in Cause No. 43975, August 27, 2014 in Cause No. 44374 and November 13, 2018 in Cause No. 37399-GCA 140.

Q10. PLEASE DESCRIBE ATTACHMENT JFL-3 IN MORE DETAIL.

A10. Schedules 1 through 5 of Attachment JFL-3 support the calculation of the GCA Factors. Schedule 1 is the monthly calculation of the GCA Factors based on Load Forecast (Schedule 2), the estimated purchases and gas cost (Schedule 3), allocation factors associated with the rate class and period (Schedule 4), and storage cost (Schedule 5) for the projection period of December 2023, January and February 2024.

Schedules 6 through 12 of Attachment JFL-3 are the reconciliation of actual gas costs and recoveries for June, July and August 2023. Schedule 6 shows the actual gas costs and variance calculation of gas cost incurred versus recoveries in the reconciliation period of June, July and August 2023. Schedule 7 is the calculation of actual gas costs in the period based on purchases (Schedule 8), unnominated gas cost (Schedule 9), and storage injections/withdrawals (Schedule 10). Schedule 11 calculates the Unaccounted for Gas ("UAFG") percentage. Schedule 12 allocates the variance from the reconciliation period across the next four quarters. The variance to be included in this GCA 160 is based on components from this GCA and the three previous GCAs, as well as refunds and write-offs for the upcoming projection periods.

PROJECTION PERIOD

Q11. HOW DID CITIZENS GAS PROJECT THE GAS PRICES FOR THE MONTHS OF DECEMBER 2023, JANUARY AND FEBRUARY 2024?

A11. The majority of the gas costs for December 2023, January and February 2024 were projected using the NYMEX futures prices at Henry Hub for the three-month period. The index is the same index by which Citizens Gas has priced its commodity purchases in the past. The futures prices are adjusted for basis, fuel and transportation for delivery to Citizens Gas' city-gate.

Table 1

NYMEX Price as of 9/14/23	
Sep. 2023	$3.436
Oct. 2023	$3.684
Nov. 2023	$3.610

Q12. ON WHAT ARE THE OTHER GCA COMPUTATIONS CONTAINED IN ATTACHMENT JFL - 3 BASED?

A12. The rates and charges reflected in the transportation and storage costs are based upon pipeline tariffs. The other major components of estimated gas costs are non-pipeline gas costs, which are priced in accordance with the Commission's Order in Cause No. 37475, and purchases from gas suppliers other than pipelines, including financial hedge transactions, as discussed later in my testimony.

Q13. WHAT PERCENTAGE OF TOTAL PURCHASES IS MADE UP OF FINANCIALLY HEDGED TRANSACTIONS FOR THE MONTHS OF DECEMBER 2023, JANUARY AND FEBRUARY 2024?

A13. Financially hedged transactions account for 14.97% of total purchases for the months of December 2023, January and February 2024.

Q14. DO PETITIONER'S GAS SUPPLIES INCLUDE ANY NON-TRADITIONAL SUPPLIES OF GAS?

A14. No. But, if there were any non-traditional gas supplies included in the GCA 160 computation, they would be priced at the lesser of the equivalent cost of pipeline gas or the authorized per unit price, as authorized by the Commission in Cause No. 37475.

Q15. DO YOU BELIEVE THAT THE PROPOSED GCA RATES FOR DECEMBER 2023, JANUARY AND FEBRUARY 2024 ARE ACCURATE?

A15. Yes, I do.

RECONCILIATION PERIOD

Q16. HAVE YOU COMPARED PETITIONER'S ESTIMATED GAS COSTS FOR THE PERIOD OF JUNE, JULY AND AUGUST 2023 WITH ACTUAL GAS COSTS EXPERIENCED FOR THAT RECOVERY PERIOD PURSUANT TO IC 8-1-2-42(G)(3)(D)?

A16. Yes.

Q17. IN YOUR OPINION, ARE THE GAS COST VARIANCES INCLUDED WITHIN THIS GCA 160 PROCEEDING ACCURATE AND REASONABLE?

A17. Yes. The resulting percentages of total monthly variance to the total gas costs incurred and the average variance percentage for the trailing 12-month period ending with each of the three months June, July and August 2023 presented in the GCA reconciliation period are shown in Table 2:

Table 2

Twelve Months Ending	Actual Gas Cost	Variance	% Variance
June 2023	$135,814,356	$5,037,809	3.71%
July 2023	$136,016,898	$3,904,651	2.87%
August 2023	$132,647,986	$377,727	0.28%

Q18. PLEASE EXPLAIN PETITIONER'S TWELVE-MONTH TRAILING AVERAGES FOR ANY MONTH WITHIN THE GCA RECONCILIATION PERIOD THAT ARE GREATER THAN +/- 10% SHOWN ON ATTACHMENT JFL-3, SCHEDULE 6D.

A18. The 12-month trailing averages for each of the months in the reconciliation period do not exceed the Commission approved level of +/- 10%

Q19. DO THE PROPOSED GCA 160 RATES INCLUDE THE ANNUAL TRUE-UP FOR COST OF UAFG?

A19. Yes. Pursuant to Commission approval in Cause No. 37399-GCA95, the proposed GCA rates to be effective December 2023, January and February 2024, include the effect of reconciling actual UAFG costs incurred for the twelve-month period of September 2022 through August 2023 to actual UAFG cost recoveries for the same period. The UAFG percentage established in Citizens Gas' last general rate case, Cause No. 43975, is 1.36%. The reconciliation of UAFG costs shown on Schedule 11A of Attachment JFL- 3 results in a refund of $1,281,004.

Q20. DO THE PROPOSED GCA 160 RATES INCLUDE A RECONCILIATION OF ACTUAL COSTS TO ACTUAL RECOVERIES FOR THE MONTHS OF JUNE, JULY AND AUGUST 2023?

A20. Yes. The proposed GCA rates to be effective December 2023, January and February 2024 include the effect of reconciling actual gas costs incurred for the months of June, July and August 2023 to actual cost recoveries. In accordance with the Commission's August 14, 1986 Order in Cause No. 37091, the gas supply variance was calculated for each customer demand class and is summarized by class on Attachment JFL–3, Schedule 12B, page 1, lines 1 through 5 and Schedule 12B, page 2, lines 1 through 3. The actual gas supply cost incurred compared to actual gas supply revenue for each month, as depicted in Schedule 6, is shown in Table 3:

Table 3

	Net of Schedule 6 and 12C		Schedule 12
	Actual Gas Cost	**Actual Recoveries**	**Cost in Excess of Recoveries**
June 2023	$1,965,694	$2,757,523	($791,829)
July 2023	$2,282,900	$3,479,854	($1,196,954)
August 2023	$1,880,003	$3,249,582	($1,369,579)
Total	$6,128,597	$9,486,959	($3,358,362)

Q21. WHAT PERCENTAGE OF TOTAL PURCHASES WAS MADE UP OF FINANCIALLY-HEDGED TRANSACTIONS FOR THE MONTHS OF JUNE, JULY AND AUGUST 2023?

A21. Financially-hedged transactions accounted for 100.55% of total purchases for the months of June, July and August 2023.

Q22. HAS PETITIONER RECEIVED ANY NEW REFUNDS THAT ARE INCLUDED IN THIS GCA?

A22. No.

MONTHLY PRICE UPDATE

Q23. PLEASE DESCRIBE THE HISTORY OF THE MONTHLY PRICE UPDATE MECHANISM.

A23. In Cause No. 37399-GCA75, the Commission approved the use of a Monthly Price Update mechanism for twelve (12) quarterly GCAs, beginning with GCA 75 and ending with GCA 86. The Second Amended and Restated Stipulation and Settlement Agreement filed with the Commission on August 23, 2005 in Cause No. 37399-GCA 75 extended the monthly price update mechanism for another twelve (12) quarterly GCAs beginning with GCA 87 and ending with GCA 98. The Third Amended and Restated Stipulation and Settlement Agreement filed with the Commission on August 3, 2007 in Cause No. 37399-GCA75, extended the Monthly Price Update Mechanism beginning September 1, 2008 and it continues until further Order of the Commission.

Q24. HAS THE GCA PROCESS, AS DESCRIBED IN IC 8-1-2-42(G) AND INSTITUTED PURSUANT TO THE COMMISSION'S AUGUST 14, 1986 ORDER IN CAUSE NO. 37091, BEEN CHANGED IN ANY SUBSTANTIAL WAY BY THE CITIZENS GAS MONTHLY GCA MECHANISM?

A24. No. The GCA schedules filed with the GCA Petition, and potentially updated 20 days later, remain unchanged. Pursuant to IC 8-1-2-42(g), the Commission reviews all relevant Quarterly GCA evidence, conducts a summary hearing, and issues an order approving the Benchmark Prices and GCA factors for each month of the quarter.

No less than three days prior to the beginning of each month during the Quarterly GCA period, Citizens Gas files with the Commission a Monthly Price Update for the upcoming month. The GCA factors contained in the Monthly Price Update become effective on the first day of the next calendar month, without further hearing.

Q25. PLEASE DESCRIBE THE MPU FILING.

A25. Pursuant to the Commission's Order in Cause No. 44374, the MPU shall be filed no later than three business days before the beginning of the calendar month in which the rates will go into effect. The Cause No. 44374 Order allows for Petitioner to change the mix of volumes between spot, fixed, and storage injections and withdrawal volumes as long as the total volumes remain unchanged from Petitioner's total volumes approved in the applicable GCA period. The MPU is permitted to change the unit price of spot, fixed and storage gas based on current market conditions and subject to applicable price caps.

Q26. WHEN CITIZENS GAS FILES ITS MONTHLY PRICE UPDATE WITH THE COMMISSION, WHAT IS INCLUDED IN THE FILING?

A26. The Monthly Price Update includes the following: (1) a reference to Gas Daily (or other comparable publication) indicating the NYMEX close price being utilized in the Monthly Price Update; (2) a schedule reflecting adjustments made to the NYMEX close price for use in GCA schedules and comparing to the same calculation made in the Quarterly GCA; (3) certain GCA schedules that are impacted; (4) the revised tariff sheet for the upcoming month (Rider A); and (5) a residential heating customer's bill at 5, 10, 15, 20 and 25 dekatherms compared to currently effective rates and compared to the rates in effect one year ago.

Q27. FOR PURPOSES OF IDENTIFYING THE BENCHMARK PRICES AS A REQUIREMENT OF THE MONTHLY PRICE UPDATE MECHANISM, WHAT ARE THE MONTHLY BENCHMARK PRICES FOR DECEMBER 2023, JANUARY AND FEBRUARY 2024 INCLUDED IN THIS FILING?

A27. Table 4 shows the Monthly Benchmark Prices as established by NYMEX +/- basis as of September 14, 2023 by pipeline for December 2023, January and February 2024.

TABLE 4

Benchmark Prices								
	Panhandle Eastern	Texas Gas	Midwestern Gas	Panhandle PrePay	PEAK B	Rockies Express East	PEAK A	TGT-REX
Dec. 2023	$3.5694	$3.2945	$3.6973	$3.2436	$3.2285	$2.9485	$3.1560	$3.7096
Jan. 2024	$4.6083	$3.6545	$4.3746	$4.2825	$3.4765	$3.4712	$3.4040	$4.3886
Feb. 2024	$4.5406	$3.6200	$4.3049	$4.2148	$3.4025	$3.4261	$3.3300	$4.3188

Q28. HAS PETITIONER PROPERLY APPLIED ITS GCA RATES SINCE ITS LAST GCA PROCEEDING IN CAUSE NO. 37399 GCA 159?

A28. Yes.

Q29. ARE PETITIONER'S BOOKS AND RECORDS KEPT ACCORDING TO THE UNIFORM SYSTEM OF ACCOUNTS, AS PRESCRIBED BY THE COMMISSION?

A29. Yes.

GAS SUPPLY

ASSET MANAGEMENT AGREEMENT

Q30. PLEASE DESCRIBE THE ASSET MANAGEMENT AGREEMENT ("AMA") BETWEEN EXELON GENERATION COMPANY, LLC ("EXELON") AND CITIZENS GAS.

A30. The AMA was entered into on April 1, 2021 and the term will expire on March 31, 2024. Pursuant to the AMA, Exelon administers a collection of contracts (the "Portfolio Contracts"), including contracts with Panhandle Eastern Pipe Line Company ("Panhandle"), Texas Gas Transmission Corporation ("Texas Gas"), Midwestern Gas Transmission, and Rockies Express Pipeline ("REX") to meet Citizens Gas' requirements.

Q31. WHAT IS THE EXTENT OF GAS DELIVERABILITY AVAILABLE TO CITIZENS GAS UNDER THE AMA?

A31. A breakdown of the monthly maximum daily deliverability available to Citizens Gas from each of its supply sources is reflected in Table 5 below. The table includes deliverability available from Exelon via the AMA, delivered supplies from BP Canada, maximum deliverability from on-system underground storage, and maximum deliverability from a liquefied natural gas ("LNG") facility.

Table 5

	Exelon	BP	Storage	LNG	Total
Dec. 2023	231,954	20,000	100,000	100,000	451,954
Jan. 2024	231,954	20,000	100,000	100,000	451.954
Feb. 2024	231,954	20,000	100,000	100,000	451,954

Q32. PLEASE DESCRIBE GENERALLY THE GAS SALES AND DELIVERY PROVISIONS OF THE AMA.

A32. Under the AMA, Citizens Gas reserves its baseload firm gas supplies with Exelon based on the projected daily requirements Citizens Gas has for each month. Exelon then provides the amount of gas commodity Citizens Gas uses to meet the needs of its customers on a daily, seasonal, and peak day basis

Q33. WHAT ROLE DOES EXELON PLAY WITH REGARD TO CITIZENS GAS' SUPPLY CONTRACTS?

A33. Exelon administers contracts with producers and gas marketers for firm, long-term (at least one year) gas supplies sufficient to meet Citizens Gas' maximum daily requirements each month. This arrangement ensures the amount of capacity held on the respective pipelines is matched with firm gas supplies. The gas supply contracts provide for "take or release" volumes on a monthly basis. This "take or release" provision gives Citizens Gas or Exelon, on behalf of Citizens Gas, the right to nominate with the producer or supplier any volume greater than the contract minimum up to the contract maximum in any month. These contracts with producers and gas marketers are the same type of contracts which have been included in Citizens Gas' previous GCA filings. In addition, Citizens Gas enters into hedging transactions to meet its gas supply needs, pursuant to our hedging strategy.

Q34. HAS CITIZENS GAS FORECASTED ITS GAS REQUIREMENTS FOR PURPOSES OF THIS PARTICULAR GCA PROCEEDING?

A34. Yes, it has. Petitioner's Attachment JFL-3, Schedules 2A, 2B, and 2C depict Citizens Gas' estimated throughput and retail sales volumes for the twelve months ending

November 2024. Estimated sales are calculated annually based on an internal regression model that utilizes normal, 30-year average temperatures and historical data, including sales, the number of customers, and heating degree days. These forecasts use the same methodology Citizens Gas followed in its past GCA proceedings.

Q35. HOW ARE THE PROJECTED GAS SUPPLY QUANTITIES DETERMINED FOR CITIZENS GAS?

A35. In planning for its gas supply requirements, Citizens Gas calculates the total gas required on a daily, monthly and seasonal basis, as reflected in Attachments JFL-3, Schedules 2A, 2B, and 2C. Citizens Gas then considers all available supply sources in preparing a proposed gas supply plan to meet its gas supply requirements. Based upon deliverability, storage inventory levels, transportation costs, gas costs, and other inherent limitations, Citizens Gas determines the optimum supply plan to meet its retail gas requirements.

HEDGING STRATEGY

Q36. PLEASE BRIEFLY DESCRIBE CITIZENS GAS' USE OF PHYSICAL AND/OR FINANCIAL HEDGES AS PART OF ITS HEDGING STRATEGY.

A36. The primary objectives of hedging are to limit market volatility and catastrophic pricing risks for gas customers. Citizens Gas utilizes hedging instruments to mitigate fluctuation gas costs associated with system supply needs. Citizens Gas considers past, present and future market conditions and time-based restrictions to make hedging decisions. The hedge volume is determined by the projected physical natural gas demand required to serve Citizens Gas' system supply customers. Hedge instruments do not ensure that Citizens Gas will procure future gas purchases at prices below the actual market price at the time the gas is purchased and delivered.

Q37. PLEASE DESCRIBE GENERALLY THE GAS PROCUREMENT PROCESS CITIZENS GAS UTILIZES.

A37. Citizens Gas takes a blended approach to gas supply procurement that seeks to obtain a reliable supply while mitigating market volatility for its customers. Citizens Gas uses a blend of gas purchased at current market prices, gas purchased and injected into storage and financial hedges that hedge the gas cost.

On a monthly basis, Citizens Gas creates a plan that meets the projected demands of the system under normal weather. Citizens Gas optimizes swing purchases and storage capabilities, to meet the daily needs of the system based on short-term forecasts.

Q38. PLEASE DESCRIBE THE HEDGING INSTRUMENTS CITIZENS GAS CONSIDERS AND UTILIZES.

A38. Citizens Gas considers and utilizes financial hedging instruments to mitigate price volatility.

Establishing a floor (put) and a ceiling (call), below and above which the purchaser will not pay, creates a collar. If gas prices fall below the established floor, Citizens Gas effectively pays the floor price. If gas prices rise above the established ceiling, Citizens Gas' purchase price effectively is capped at the ceiling price. A collar limits the purchaser's upward gas price exposure by establishing the ceiling; however, when gas prices fall below the floor price, the purchaser is obligated to pay the floor price. When the risk is evenly balanced between the purchaser and the counter-party, cost-less collars can be entered into, which do not require a premium. When more protection is purchased than risk assumed, a premium is required to put the collar into place. The collar allows for a lower floor than typically is available from a fixed price transaction; however, with a collar the purchaser also is at risk of paying a price higher than the fixed price quote (i.e., if market prices rise subsequent to the purchase of the collar).

Financial NYMEX futures may also be used to hedge natural gas. NYMEX futures establish a price for a determined contract month. If Petitioner purchases a NYMEX future, it will earn value to reduce the physical gas costs when the settlement price or offsetting NYMEX future is greater than the trade price. Conversely, the NYMEX future loses value to increase the physical gas costs when the settlement price is less than the trade price.

If Citizens Gas purchases an index future, it will earn value to reduce the physical gas costs when the settlement price or offsetting index future is greater than the trade price. Conversely, the index future loses value to increase the physical gas costs when the settlement price or offsetting index future is less than the trade price.

Citizens Gas may also use physical NYMEX or basis hedges to mitigate price volatility. Physical hedges are negotiated with a counter-party supplier.

Q39. PLEASE DESCRIBE HOW CITIZENS GAS STRUCTURES ITS SUPPLY PORTFOLIO TO HEDGE AGAINST GAS PRICE VOLATILITY.

A39. Financially hedged volume is determined by the anticipated monthly demand. Withdrawals from storage hedge heat load, up to optimum withdrawal levels (assuming normal weather). Citizens Gas utilizes counterparty and company-owned storage assets, supply agreements and transportation contracts to provide reliable supply.

Physical supply agreements and associated financial hedges protect against NYMEX price volatility.

Q40. WHY DOESN'T CITIZENS GAS SIMPLY HEDGE 100 PERCENT OF ITS NORMAL WEATHER SENDOUT?

A40. Three primary factors have caused Citizens Gas to refrain from simply hedging 100 percent of its normal weather sendout: (1) there are practical limits on the ability of Citizens Gas to utilize greater quantities of physically-hedged gas; (2) the missed opportunity to take advantage of falling prices to lower gas costs; and (3) the potential financial exposure associated with financial hedges.

Q41. PLEASE ELABORATE ON THE FOREGOING FACTORS.

A41. Physical hedges result in a situation where Citizens Gas must take delivery of the volumes of gas hedged. Under certain operating or weather conditions, constraints on Citizens Gas' system may limit its ability to physically take the hedged volumes. To mitigate the risk associated with a potential inability to take physically-hedged volumes, Citizens Gas limits physically-hedged volumes to no more than retail base load volumes.

In order to purchase gas for its customers at the lowest gas cost reasonably possible, Citizens Gas believes it must leave some level of its gas purchases priced at index to take advantage of falling gas prices, in the event gas prices drop below the prices at which the hedges were established.

Citizens Gas assumes some risk associated with the use of financial hedges. On a daily basis, as the difference between bid and ask prices changes, the futures commission merchant may make margin calls. These calls can be significant during times of rising prices and require the use of Citizens Gas' working capital. Limitations on the use of Citizens Gas' working capital funds also restrict the level of financial hedges that can be put in place.

Q42. IS IT POSSIBLE THAT CITIZENS GAS MIGHT MAKE CHANGES IN ITS HEDGING STRATEGY IN THE FUTURE?

A42. Yes. Citizens Gas will continue to monitor market activity and adjust the portfolio allocation accordingly. The instruments and the degree to which they are utilized may vary depending on cost, market dynamics and available opportunities. Citizens Gas' hedging strategy will continue to focus on mitigating price volatility appropriate operational flexibility and protection against upward price swings.

Q43. DOES CITIZENS GAS INCUR ADDITIONAL COSTS IN THE ADMINISTRATION OF ITS HEDGING STRATEGY THAT ARE NOT RECOVERED IN BASE RATES AND WHICH SHOULD BE RECOVERABLE IN THE GCA?

A43. Yes, in addition to the premiums described above, which are other expenses related to gas costs, Citizens Gas incurs other similar costs as well, including, but not limited to, commission fees, clearing fees, National Futures Association fees, and transaction fees. In addition, Citizens Gas recognizes gains and losses on the settlement of the contract. Attachment JFL-3, Schedule 3, pages 1, 2, and 3; 8A; 8B; and 8C include certain "Hedging Transaction Costs." The Hedging Transaction Costs reflected in this GCA consist of costs necessary to administer the financial hedge program. Citizens Gas' hedging strategy is intended to address commodity purchases and transactions made to mitigate gas price volatility (i.e., to help stabilize Petitioner's retail natural gas prices).

As a result, Citizens Gas incurs unavoidable costs which are associated with its hedging strategy. In my opinion, those costs are reasonably incurred and are expenses related to gas costs that should be included for purposes of obtaining Commission approval to recover them through the GCA mechanism.

Q44. HAS PETITIONER'S HEDGING STRATEGY BEEN CONSISTENT WITH PREVIOUS YEARS?

A44. While the overall approach has been consistent -- i.e. a hedging target for winter sendout currently at 80 percent, the mix of hedge components that Petitioner uses has changed from time to time in response to market dynamics. Storage has been and continues to be a significant component of the hedging volume mix. The volumes not covered by storage are hedged using financial or physical hedges. Initially, Citizens Gas used more physical hedge contracts. However, as the dynamics of the market have changed, the mix between physical and financial hedges has shifted resulting in financial hedges being the dominant non-storage hedge component.

Q45. WHY DID PETITIONER MAKE THE SHIFT FROM FIXED-PRICE CONTRACTS TO FINANCIAL HEDGES?

A45. Petitioner had used a mix of physical fixed-price contracts and financial hedges for a period of time. However, Petitioner wanted to gain greater operational flexibility and to take advantage of falling natural gas prices for the benefit of its gas customers.

Physical fixed-price contracts are settled in an exchange for the physical product -- i.e. the actual delivery of natural gas to the purchasing counterparty. Obviously, Petitioner needs natural gas to serve its customers. However, there are times, as mentioned earlier, when it is disadvantageous for Petitioner to take delivery of the physical gas. In contrast, financial hedges could be NYMEX futures, NYMEX call or put options, basis futures or index futures. While financial hedges are related to an underlying volume of natural gas, they are settled financially -- i.e. an exchange of goods is not required. With financial hedges, Petitioner still needs to purchase natural gas on the market to physically receive supply. In scenarios where the amount of natural gas actually needed is less than that which has been hedged, financial hedges allow Petitioner to settle the hedges financially and simply apply the gain or loss to the cost of gas actually purchased. In other words, with a financial hedge, Petitioner would not be required to accept delivery of gas that it does not need. Thus, Petitioner gains increased operational flexibility through the use of financial hedges because it can hedge the volumes needed based on its supply plan, yet "flex" the amount actually purchased based on observed customer demand. Similar to fixed-price contracts, financial hedges, and in particular call options, provide the requisite protection against unexpected and significant upward changes in the market price of natural gas. However, financial hedges also allow Petitioner to take advantage of market prices in a declining market. This contrasts to a fixed-price contract where the purchaser must pay the agreed upon price regardless of what the market price may be. In a market where the market price of natural gas is increasing and exceeds the strike price of the options, the financial hedges are "in the money." Here, Petitioner would purchase the volumes in the market and offset that market price with proceeds from the financial settlement of the hedge. The combination of these two transactions results in a net acquisition price of the financial hedge strike price and the transaction cost of the hedge. In a falling market, where the market price of natural gas is decreasing and is below the strike price, financial hedges are "out of the money." In that case, Petitioner would purchase the physical volumes at the market price and the financial hedges would expire valueless. The combination of these two transactions results in a net acquisition price of the market price and the transaction cost of the hedge.

Q46. IS IT REALISTIC TO BELIEVE THAT PETITIONER'S HEDGING STRATEGY, OR THAT OF ANY GAS UTILITY, WOULD GENERATE THE ABSOLUTE LOWEST COST OF NATURAL GAS?

A46. No. It is not realistic. Financial theory shows us that when hedging any asset with an option, the net cost of the asset always will be higher than the market price because of the addition of the cost of the option. Furthermore, the cost of natural gas does not have to be the absolute lowest cost to be recoverable in the GCA process. Rather, under Indiana Code 8-1-2-42(g)(3)(A), the petitioning gas utility must show that "…the gas utility has made every reasonable effort to acquire long term gas supplies so as to provide gas to its retail customers at the *lowest gas cost reasonably possible*…." (emphasis added)

PREPAID NATURAL GAS PURCHASES

Q47. PLEASE PROVIDE FURTHER INFORMATION ON CITIZENS GAS' PURCHASES FROM THE PUBLIC ENERGY AUTHORITY OF KENTUCKY ("PEAK").

A47. PEAK was formed to provide discounted prepay gas to its municipal members. PEAK approached Citizens Gas about a potential prepaid gas opportunity similar to the IMGPA transaction. In February 2018, Petitioner entered into an agreement with PEAK to purchase discounted prepay natural gas. The transaction has a term of thirty years divided into five periods of six years each. During each six-year period, members of PEAK may elect to participate or not depending on the availability and the minimum threshold of the discount. If the minimum discount is not available, members have no purchase obligations for that period. Citizens Gas' customers will receive the benefit directly through commodity purchases in the GCA.

Effective with gas delivered April 1, 2018, Citizens Gas began purchasing approximately 10,000 Dth per day at a 39 cent per Dth discount from index prices. This discount for gas purchases was effective through October 31, 2020. The discount changed to 33.5 cents per Dth starting November 1, 2020 through October 31, 2023 and 28 cents per Dth discount from November 1, 2023 through February 29, 2024

In March 2020, Petitioner entered into a second agreement with PEAK to purchase additional discounted prepay natural gas. Effective with gas delivered November 1, 2020, Citizens Gas will begin purchasing an additional 10,000 Dth per day at a discount of 20.75 cents per Dth from index prices. This discount will remain for gas purchases through April 30, 2026.

LOAD FORECAST

Q48. HAS PETITIONER'S ANNUAL LOAD FORECAST CHANGED SINCE THE PREVIOUS GCA?

A48. Yes.

Q49. PLEASE DESCRIBE THE CHANGES MADE TO PETITIONER'S ANNUAL LOAD FORECAST.

A49. Petitioner has updated sales volumes after analyzing customer usage. These updated sales volumes affect all rate classes and will continue to be analyzed on a quarterly basis. Thus, it is important to accurately reflect customer usage to minimize variances from projected volumes to actual volumes.

WHOLESALE SERVICES

Q50. IN CAUSE NO. 45577, THE COMMISSION DECLINED JURISDICTION OVER CITIZENS GAS'S SALES OF NATURAL GAS IN THE WHOLESALE MARKET FOR NATURAL GAS AND AUTHORIZED CITIZENS GAS TO PASS BACK THE MARGIN ON SUCH SALES TO RETAIL CUSTOMERS VIA THE GCA. HAS CITIZENS GAS BEEN ENGAGED IN WHOLESALE NATURAL GAS SALES?

A50. Yes, Citizens Gas did engage in wholesale natural gas sales in the months of June, July and August 2023. The associated volume and revenue with these sales are included on Schedule 8. Citizens Gas has entered into short-term and long-term agreements for sales of natural gas in the wholesale market for natural gas and anticipates entering into additional short-term and long-term transactions for such sales.

STORAGE WACOG CALCULATION

Q51. PLEASE DESCRIBE THE CURRENT STORAGE WEIGHTED AVERAGE COST OF GAS "WACOG" CALCULATION.

A51. Currently, when Petitioner injects natural gas into storage, the Commodity and Demand charges are added to the current Commodity and Demand charges associated with natural gas in storage. A new total cost of natural gas is calculated and then divided by the total amount of dekatherms in storage to determine the new WACOG.

Q52. HOW WOULD PETITIONER CHANGE THE CURRENT CALCULATION OF WACOG?

A52. Petitioner is proposing to treat the Storage WACOG like our other peer natural gas utilities. Petitioner would still include the Commodity cost in the Storage WACOG calculation, but would pass all Demand charges through the GCA in the month incurred. There would be roughly a fifty cent decrease on the Storage WACOG calculation. The customers will see little impact in the overall amount of their total bills. Petitioner proposes starting this change with the injection season beginning April 2024 in GCA 161.

Q53. HAS PETITIONER DISCUSSED THIS POTENTIAL CHANGE WITH THE OUCC?

A53. Yes, Petitioner has discussed this potential change with the OUCC. The OUCC does not disagree with this change and would be in favor of moving forward with the change.

CONCLUSION

Q54. DOES THIS CONCLUDE YOUR TESTIMONY?

A54. Yes, it does.

VERIFICATION

The undersigned affirms under the penalties for perjury that the foregoing testimony is true to the best of his knowledge, information, and belief.

John F. Lamb

John F. Lamb

Tab 3

RIDER A

CURRENT GAS SUPPLY CHARGES

Listed below are the charges applicable to the Utility's Gas Supply Services for all Therms delivered on or after December 1, 2023

1. Gas Rate No. S1 Variable Rate Supply: $ per Therm

Gas Rate No. D1	Gas Supply Charge	$	**0.3853**
Gas Rate No. D2	Gas Supply Charge	$	**0.4042**
Gas Rate No. D3	Gas Supply Charge	$	**0.3591**
Gas Rate No. D4	Gas Supply Charge	$	**0.3815**
Gas Rate No. D5	Gas Supply Charge	$	**-**
Gas Rate No. D7	Gas Supply Charge	$	**0.3591**

2. Gas Rate No. S2 Back-up Gas Supply Service: $ per Therm

Capacity	$	**0.0641**
Commodity	$	**0.3228**
Gas Supply Charge	$	**0.3869**

3. Balancing Charges: $ per Therm

Gas Rate No. D3	$	**0.0009**	$	**-**	for Basic Delivery Service Option
Gas Rate No. D4	$	**0.0012**	$	**0.0001**	for Basic Delivery Service Option
Gas Rate No. D5	$	**0.0021**	$	**0.0001**	for Basic Delivery Service Option
Gas Rate No. D7	$	**0.0009**			
Gas Rate No. D9	$	**0.0189**	$	**0.0009**	for Basic Delivery Service Option

Citizens Gas
2020 North Meridian Street
Indianapolis, IN 46202

One-Hundred Forty-Eighth Revised Page No. 501
Superseding One-Hundred Forty-Seventh Revised Page No. 501

RIDER A

CURRENT GAS SUPPLY CHARGES

Listed below are the charges applicable to the Utility's Gas Supply Services for all Therms delivered on or after January 1, 2024

1. Gas Rate No. S1 Variable Rate Supply: $ per Therm

Gas Rate No. D1	Gas Supply Charge	$	**0.3887**
Gas Rate No. D2	Gas Supply Charge	$	**0.4149**
Gas Rate No. D3	Gas Supply Charge	$	**0.3773**
Gas Rate No. D4	Gas Supply Charge	$	**0.3955**
Gas Rate No. D5	Gas Supply Charge	$	-
Gas Rate No. D7	Gas Supply Charge	$	**0.3773**

2. Gas Rate No. S2 Back-up Gas Supply Service: $ per Therm

Capacity	$	**0.0639**
Commodity	$	**0.3375**
Gas Supply Charge	$	**0.4014**

3. Balancing Charges: $ per Therm

Gas Rate No. D3	$	**0.0008**	$	**0.0000**	for Basic Delivery Service Option
Gas Rate No. D4	$	**0.0011**	$	**0.0001**	for Basic Delivery Service Option
Gas Rate No. D5	$	**0.0020**	$	**0.0001**	for Basic Delivery Service Option
Gas Rate No. D7	$	**0.0008**			
Gas Rate No. D9	$	**0.0188**	$	**0.0009**	for Basic Delivery Service Option

Citizens Gas
2020 North Meridian Street
Indianapolis, IN 46202

RIDER A

CURRENT GAS SUPPLY CHARGES

Listed below are the charges applicable to the Utility's Gas Supply Services for all Therms delivered on or after February 1, 2024

1. Gas Rate No. S1 Variable Rate Supply: $ per Therm

Gas Rate No. D1	Gas Supply Charge	$	**0.3926**
Gas Rate No. D2	Gas Supply Charge	$	**0.4054**
Gas Rate No. D3	Gas Supply Charge	$	**0.3769**
Gas Rate No. D4	Gas Supply Charge	$	**0.3826**
Gas Rate No. D5	Gas Supply Charge	$	**-**
Gas Rate No. D7	Gas Supply Charge	$	**0.3769**

2. Gas Rate No. S2 Back-up Gas Supply Service: $ per Therm

Capacity	$	**0.0597**
Commodity	$	**0.3299**
Gas Supply Charge	$	**0.3896**

3. Balancing Charges: $ per Therm

Gas Rate No. D3	$	**0.0007**	$	**0.0000**	for Basic Delivery Service Option
Gas Rate No. D4	$	**0.0010**	$	**0.0001**	for Basic Delivery Service Option
Gas Rate No. D5	$	**0.0019**	$	**0.0001**	for Basic Delivery Service Option
Gas Rate No. D7	$	**0.0007**			
Gas Rate No. D9	$	**0.0187**	$	**0.0009**	for Basic Delivery Service Option

Tab 4

CITIZENS GAS

Impact Statement for Residential Heating Customers

Proposed GCA Factor December 2023
vs.
Currently Approved GCA Factor October 2023

Table No. 1

Consumption Dth	Bill At Proposed GCA Factor $4.0420	Bill At Current GCA Factor $5.4250	Dollar Increase (Decrease)	Percent Change
5	$48.00	$54.91	($6.91)	(12.58)%
10	$79.73	$93.56	($13.83)	(14.78)%
15	$111.47	$132.21	($20.74)	(15.69)%
20	$143.20	$170.86	($27.66)	(16.19)%
25	$174.94	$209.51	($34.57)	(16.50)%

Proposed GCA Factor December 2023
vs.
GCA Factor One Year Ago December 2022

Table No. 2

Consumption Dth	Bill At Proposed GCA Factor $4.0420	Bill At Prior Year's GCA Factor $5.4230	Dollar Increase (Decrease)	Percent Change
5	$48.00	$54.82	($6.82)	(12.44)%
10	$79.73	$93.38	($13.65)	(14.62)%
15	$111.47	$131.94	($20.47)	(15.51)%
20	$143.20	$170.50	($27.30)	(16.01)%
25	$174.94	$209.06	($34.12)	(16.32)%

CITIZENS GAS

Impact Statement for Residential Heating Customers

Proposed GCA Factor January 2024
vs.
Currently Approved GCA Factor October 2023

Table No. 1

Consumption Dth	Bill At Proposed GCA Factor $4.1490	Bill At Current GCA Factor $5.4250	Dollar Increase (Decrease)	Percent Change
5	$48.53	$54.91	($6.38)	(11.62)%
10	$80.80	$93.56	($12.76)	(13.64)%
15	$113.07	$132.21	($19.14)	(14.48)%
20	$145.34	$170.86	($25.52)	(14.94)%
25	$177.61	$209.51	($31.90)	(15.23)%

Proposed GCA Factor January 2024
vs.
GCA Factor One Year Ago January 2023

Table No. 2

Consumption Dth	Bill At Proposed GCA Factor $4.1490	Bill At Prior Year's GCA Factor $5.5470	Dollar Increase (Decrease)	Percent Change
5	$48.53	$55.45	($6.92)	(12.48)%
10	$80.80	$94.63	($13.83)	(14.61)%
15	$113.07	$133.82	($20.75)	(15.51)%
20	$145.34	$173.00	($27.66)	(15.99)%
25	$177.61	$212.19	($34.58)	(16.30)%

CITIZENS GAS

Impact Statement for Residential Heating Customers

Proposed GCA Factor February 2024
vs.
Currently Approved GCA Factor October 2023

Table No. 1

Consumption Dth	Bill At Proposed GCA Factor $4.0540	Bill At Current GCA Factor $5.4250	Dollar Increase (Decrease)	Percent Change
5	$48.06	$54.91	($6.85)	(12.47)%
10	$79.85	$93.56	($13.71)	(14.65)%
15	$111.65	$132.21	($20.56)	(15.55)%
20	$143.44	$170.86	($27.42)	(16.05)%
25	$175.24	$209.51	($34.27)	(16.36)%

Proposed GCA Factor February 2024
vs.
GCA Factor One Year Ago February 2023

Table No. 2

Consumption Dth	Bill At Proposed GCA Factor $4.0540	Bill At Prior Year's GCA Factor $5.3980	Dollar Increase (Decrease)	Percent Change
5	$48.06	$54.70	($6.64)	(12.14)%
10	$79.85	$93.14	($13.29)	(14.27)%
15	$111.65	$131.58	($19.93)	(15.15)%
20	$143.44	$170.02	($26.58)	(15.63)%
25	$175.24	$208.46	($33.22)	(15.94)%

Tab 5

Citizens Gas
Determination of Gas Supply Charge with Demand Cost Allocated
Estimated For December 2023

Line No.		A Demand	B Commodity and Other	C Total
	Estimated Cost of Gas			
1	Purchased gas cost (Schedule 3, Page 1, ln 16)	$1,747,417	$8,077,173	$9,824,590
2	PEPL Unnominated Quantities cost (Schedule 4 pg 1, ln 16 col A + ln 23)	-	785,134	785,134
3	Gas (injected into) withdrawn from storage - net cost (Schedule 5, ln 3)	1,033,634	7,048,564	8,082,198
4	Total estimated gas cost (ln 1 through ln 3)	$2,781,051	$15,910,871	$18,691,922
5	Total Gas Supply variance (Sch 1, December, total of ln 17)	-	(134,662)	(134,662)
6	Total Balancing Demand variance (Sch 1 pg 2 ln 11 + Sch. 1, ln 28)	-	(22,664)	(22,664)
7	Dollars to be refunded (Schedule 12A, ln 16 * Sch 2B, ln 27, col. F)	-	-	-
8	Total cost to be recovered through GCA (ln 4 + ln 5 + ln 6 - ln 7)	$2,781,051	$15,753,545	$18,534,596
9	Net Write-Off Recovery Costs (ln 8 *1.10%)			$203,881
10	Total cost to be recovered through GCA (ln. 8 + ln 9)			$18,738,477

Citizens Gas
Determination of Gas Supply Charge with Demand Cost Allocated
Estimated For December 2023
To Be Applied To December 2023

Line No.		A Gas Rate No. D1	B Gas Rate No. D2	C Gas Rate No. D3/No. D7	D Gas Rate No. D4	E Gas Rate No. D5
	Calculation of Gas Supply Charge per Unit (Dth)					
11	Balancing Demand Cost Variance (Sch12B, pg. 2, ln 13 * Sch 2C, ln 22)	($113)	($14,203)	-	-	-
12	Throughput excluding Basic - Dth (Sch 2C, ln 1)	18,155	3,306,985	-	-	-
13	Total Balancing Demand Cost variance per unit of throughput (ln 11 / ln 12)	($0.006)	($0.004)	-	-	-
14	Retail demand cost per unit sales (Sch 1A, pg 1 ln 8)	0.495	0.608	0.261	0.541	-
15	Monthly balancing demand cost per unit for GR D1 & D2 only (Sch 1A, pg 1, ln 11)	0.007	0.007	-	-	-
16	Total demand cost to be recovered through GCA (ln 13 + ln 14 + ln 15)	$0.496	$0.611	$0.261	$0.541	$0.000
17	Total Gas Supply variance (Sch 12B, pg 1, ln 15) * (Sch 2B, ln 27)	(639)	(20,376)	8,429	(122,076)	0
18	Dollars to be refunded ((ln 7) * Sch 2B, ln 23)	0	0	0	0	0
19	Other non-demand gas costs (ln 4, col B - ln 2, col B) * (Sch 2B, ln 23)	58,295	10,619,084	304,511	4,143,847	0
20	Total monthly non-demand costs to be recovered through Gas Supply Charge (ln 17 - ln 18 + ln 19)	$57,656	$10,598,708	$312,940	$4,021,771	$0
21	Sales subject to GCA - Dth (Schedule 2B, ln 1)	18,155	3,306,985	94,831	1,290,473	0
22	Total monthly non-demand costs per unit sales (ln 20 / ln 21)	$3.176	$3.205	$3.300	$3.117	$0.000
23	Net Write-Off Recovery Cost (Sch 1C, pg 1, ln 4)	0.047	0.056	0.006	0.013	0.000
24	PEPL Unnominated Quantites Retail Cost (Schedule 4, pg. 1 ln 8)	0.123	0.159	0.024	0.144	0.000
25	PEPL Balancing Cost for Gas Rates D1 & D2 only (Sch 4, pg 1, ln 15)	0.011	0.011	-	-	-
26	Gas Supply Charge to be recovered through GCA (ln 16 + ln 22 + ln 23 + ln 24 + ln 25)	$3.853	$4.042	$3.591	$3.815	$0.000

Citizens Gas
Determination of Balancing Demand Charge per Unit (Dth)
Estimated for the Period December 2023
To Be Applied to the December 2023 Throughput

Line No.		A Gas Rate No. D3/No. D7	B Gas Rate No. D4	C Gas Rate No. D5	D Gas Rate No. D9
	Calculation of Balancing Demand Charge per Unit (Dth)				
27	Balancing Demand Cost Variance (Sch12B, pg. 2, ln 13 * Sch 2C, ln 22)	($2,439)	($11,300)	$781	$4,610
28	Throughput excluding Basic - Dth (Sch 2C, ln 1)	271,299	2,017,919	270,568	26,970
29	Total Balancing Demand Cost variance per unit of throughput (ln 27 / ln 28)	($0.009)	($0.006)	$0.003	$0.171
30	Monthly balancing demand charge per unit of throughput (Sch 1A, pg 1, ln 11)	0.007	0.007	0.007	0.007
31	PEPL balancing demand charge per unit of throughput (Sch 4, pg 1, ln 15)	0.011	0.011	0.011	0.011
32	Total balancing demand charge per unit of throughput (ln 29 + ln 30 + ln 31)	0.009	0.012	0.021	0.189

Citizens Gas
Determination of Basic Balancing Charge
Estimated for December 2023
To Be Applied to December 2023

Line No.		A Gas Rate No. D3/No. D7	B Gas Rate No. D4	C Gas Rate No. D5	D Gas Rate No.D9
	Calculation of Basic Balancing Charge per unit (Dth)				
33	Basic balancing charge per unit ((Sch 1, ln 29 + ln 30 + ln 31) * .05)	0.000	0.001	0.001	0.009

Citizens Gas
Determination of Back-up Gas Supply Charge
Estimated for December 2023
To Be Applied to December 2023

Line No.	Calculation of Back-up Gas Supply Charge per unit (Dth)	
34	PEPL retail demand costs for Gas Rate Nos. D3 & D4 (Sch 4, pg 1, ln 2)	$164,877
35	Monthly retail demand costs for Gas Rate Nos. D3 & D4 (Sch 1A, pg 1, ln 6)	722,515
36	Total retail demand costs for Gas Rates Nos. D3 & D4 (ln 34 + ln 35)	$887,392
37	Estimated monthly retail sales Dths for Gas Rates D3 & D4 (Sch. 2B, line 1)	1,385,304
38	Back-up supply capacity charge per unit (ln 36 / ln 37)	$0.641
39	PEPL monthly variable costs for Gas Rate Nos. D3 & D4 (Sch 4, pg 1, ln 5)	$23,465
40	Total monthly non-demand costs for Gas Rate Nos. D3 & D4 (Sch 1, ln 19 - ln 18)	4,448,358
41	Total retail non-demand costs for Gas Rates Nos. D3 & D4 (ln 39 + ln 40)	$4,471,823
42	Estimated monthly retail sales Dths for Gas Rates D3 & D4 (Sch. 2B, ln 1)	1,385,304
43	Back-up supply commodity charge per unit (ln 41 / ln 42)	$3.228
44	Total Back-up Gas Supply Charge (ln 38 + ln 43)	$3.869

Citizens Gas
Determination of Gas Supply Charge with Demand Cost Allocated
Estimated for January 2024

Line No.		A Demand	B Commodity and Other	C Total
	Estimated Cost of Gas			
1	Purchased gas cost (Schedule 3, Page 2, ln 16)	$1,747,418	$8,867,534	$10,614,952
2	PEPL Unnominated Quantities cost (Schedule 4 pg 2, ln 16 col A + ln 23)	-	818,235	$818,235
3	Gas (injected into) withdrawn from storage - net cost (Schedule 5, ln 6)	1,295,539	8,815,657	$10,111,196
4	Total estimated gas cost (ln 1 through ln 3)	$3,042,957	$18,501,426	$21,544,383
5	Total Gas Supply variance (Sch 1, January, total of ln 17)	-	(148,770)	($148,770)
6	Total Balancing Demand variance (Sch 1 pg 2 ln 11 + Sch. 1, ln 28)		(25,564)	($25,564)
7	Dollars to be refunded (Schedule 12A, ln 16 * Sch 2B, ln 28, col. F)	-	-	-
8	Total cost to be recovered through GCA (ln 4 + ln 5 + ln 6 - ln 7)	$3,042,957	$18,327,092	$21,370,049
9	Net Write-Off Recovery Costs (ln 8 * 1.10%)			$235,071
10	Total cost to be recovered through GCA (ln. 8 + ln 9)			$21,605,120

Citizens Gas
Determination of Gas Supply Charge with Demand Cost Allocated
Estimated for January 2024
To Be Applied to January 2024 Sales

Line No.		A Gas Rate No. D1	B Gas Rate No. D2	C Gas Rate No. D3/No. D7	D Gas Rate No. D4	E Gas Rate No. D5
	Calculation of Gas Supply Charge per Unit (Dth)					
11	Balancing Demand Cost Variance (Sch 12B, pg 2, ln 13 * Sch 2C, ln 23)	($147)	($16,119)	-	-	-
12	Throughput excluding Basic - Dth (Sch 2C, ln 2)	23,596	3,753,038	-	-	-
13	Total Balancing Demand Cost per unit of throughput (ln 11 / ln 12)	($0.006)	($0.004)	-	-	-
14	Retail demand cost per unit sales (Sch 1A, pg 2 ln 8)	0.417	0.587	0.298	0.544	-
15	Monthly balancing demand cost per unit for GR D1 & D2 only (Sch 1A, pg 2, ln 11)	0.006	0.006	-	-	-
16	Total demand cost to be recovered through GCA (ln 13 + ln 14 + ln 15)	$0.417	$0.589	$0.298	$0.544	$0.000
17	Total Gas Supply variance (Sch 12B, pg 1, ln 15) * (Sch 2B, ln 28)	(831)	(23,124)	8,103	(132,918)	0
18	Dollars to be refunded ((ln 7) * Sch 2B, ln 24)	0	0	0	0	0
19	Other non-demand gas costs (ln 4, col B - ln 2, col B) * (Sch 2B, ln 24)	79,132	12,586,241	305,707	4,712,111	0
20	Total monthly non-demand costs to be recovered through Gas Supply Charge (ln 17 - ln 18 + ln 19)	$78,301	$12,563,117	$313,810	$4,579,193	$0
21	Sales subject to GCA - Dth (Schedule 2B, ln 2)	23,596	3,753,038	91,160	1,405,082	0
22	Total monthly non-demand costs per unit sales (ln 20 / ln 21)	$3.318	$3.347	$3.442	$3.259	$0.000
23	Net Write-Off Recovery Cost (Sch 1C, pg 2, ln 4)	0.042	0.057	0.007	$0.014	$0.000
24	PEPL Unnominated Quantites Retail Cost (Sch 4, pg 2 ln 8)	0.099	0.145	0.026	0.138	0.000
25	PEPL Balancing Cost for Gas Rates D1 & D2 only (Sch 4, pg 2, ln 15)	0.011	0.011	-	-	-
26	Gas Supply Charge to be recovered through GCA (ln 16 + ln 22 + ln 23 + ln 24 + ln 25)	$3.887	$4.149	$3.773	$3.955	$0.000

Citizens Gas
Determination of Balancing Demand Charge per Unit (Dth)
Estimated for January 2024
To Be Applied to the January 2024 Throughput

Line No.		A Gas Rate No. D3/No. D7	B Gas Rate No. D4	C Gas Rate No. D5	D Gas Rate No. D9
	Calculation of Balancing Demand Charge per Unit (Dth)				
27	Balancing Demand Cost Variance (Sch12B, pg. 2, ln 13 * Sch 2C, ln 23)	($2,439)	($12,450)	$832	$4,759
28	Throughput excluding Basic - Dth (Sch 2C, ln 2)	271,348	2,223,296	288,486	27,838
29	Total Balancing Demand Cost variance per unit of throughput (ln 27 / ln 28)	(0.009)	(0.006)	0.003	0.171
30	Monthly balancing demand charge per unit of throughput (Sch 1A, pg 2, ln 11)	0.006	0.006	0.006	0.006
31	PEPL balancing demand charge per unit of throughput (Sch 4, pg 2, ln 15)	0.011	0.011	0.011	0.011
32	Total balancing demand charge per unit of throughput (ln 29 + ln 30 + ln 31)	0.008	0.011	0.020	0.188

Citizens Gas
Determination of Basic Balancing Charge
Estimated for January 2024
To Be Applied to January 2024

Line No.		A Gas Rate No. D3/No. D7	B Gas Rate No. D4	C Gas Rate No. D5	D Gas Rate No. D9
	Calculation of Basic Balancing Charge per unit (Dth)				
33	Basic balancing charge per unit ((Sch 1, ln 29 + ln 30 + ln 31) * .05)	0.000	0.001	0.001	0.009

Citizens Gas
Determination of Back-up Gas Supply Charge
Estimated for January 2024
To Be Applied to January 2024

Line No.		
	Calculation of Back-up Gas Supply Charge per unit (Dth)	
34	PEPL retail demand costs for Gas Rate Nos. D3 & D4 (Sch 4, pg 2, ln 2)	$164,877
35	Monthly retail demand costs for Gas Rate Nos. D3 & D4 (Sch 1A, pg 2, ln 6)	791,555
36	Total retail demand costs for Gas Rates Nos. D3 & D4 (ln 34 + ln 35)	$956,432
37	Estimated Monthly retail sales Dths for Gas Rates D3 & D4 (Sch. 2B, line 2)	1,496,242
38	Back-up supply capacity charge per unit (ln 36 / ln 37)	$0.639
39	PEPL monthly variable costs for Gas Rate Nos. D3 & D4 (Sch 4, pg 2, ln 5)	$31,405
40	Total monthly non-demand costs for Gas Rate Nos. D3 & D4 (Sch 1, ln 19 - ln 18)	5,017,818
41	Total retail non-demand costs for Gas Rates Nos. D3 & D4 (ln 39 + ln 40)	$5,049,223
42	Estimated monthly retail sales Dths for Gas Rates D3 & D4 (Sch. 2B, ln 2)	1,496,242
43	Back-up supply commodity charge per unit (ln 41 / ln 42)	$3.375
44	Total Back-up Gas Supply Charge (ln 38 + ln 43)	$4.014

Citizens Gas
Determination of Gas Supply Charge with Demand Cost Allocated
Estimated for February 2024

Line No.		A Demand	B Commodity and Other	C Total
	Estimated Cost of Gas			
1	Purchased gas cost (Schedule 3, Page 3, ln 16)	$1,654,993	$8,094,354	$9,749,347
2	PEPL Unnominated Quantities cost (Schedule 4 pg 3, ln 16 col A + ln 23)	-	768,182	768,182
3	Gas (injected into) withdrawn from storage - net cost (Schedule 5, ln 9)	1,497,887	10,260,126	11,758,013
4	Total estimated gas cost (ln 1 through ln 3)	$3,152,880	$19,122,662	$22,275,542
5	Total Gas Supply variance (Sch 1, February, total of ln 17)	-	(165,490)	(165,490)
6	Total Balancing Demand variance (total of Sch 1 pg 2 ln 11 + Sch. 1, ln 28)		(26,559)	(26,559)
7	Dollars to be refunded (Schedule 12A, ln 16 * Sch 2B, ln 29, col. F)	-	-	-
8	Total cost to be recovered through GCA (ln 4 + ln 5 + ln 6 - ln 7)	$3,152,880	$18,930,613	$22,083,493
9	Net Write-Off Recovery Costs (ln 8 * 1.10%)			$242,918
10	Total cost to be recovered through GCA (ln. 8 + ln 9)			$22,326,411

Citizens Gas
Determination of Gas Supply Charge with Demand Cost Allocated
Estimated for February 2024
To Be Applied to February 2024 Sales

Line No.		A Gas Rate No. D1	B Gas Rate No. D2	C Gas Rate No. D3/No. D7	D Gas Rate No. D4	E Gas Rate No. D5
	Calculation of Gas Supply Charge per Unit (Dth)					
11	Balancing Demand Cost Variance (Sch 12B, pg 2, ln 13 * Sch 2C, ln 24)	($124)	($16,907)	-	-	-
12	Throughput excluding Basic - Dth (Sch 2C, ln 3)	20,025	3,936,578	-	-	-
13	Total Balancing Demand Cost per unit of throughput (ln 11 / ln 12)	($0.006)	($0.004)	-	-	-
14	Retail demand cost per unit sales (Sch 1A, pg 3 ln 8)	$0.510	$0.580	$0.362	$0.509	-
15	Monthly balancing demand cost per unit for GR D1 & D2 only (Sch 1A, pg 3, ln 11)	0.005	0.005	-	-	-
16	Total demand cost to be recovered through GCA (ln 13 + ln 14 + ln 15)	$0.509	$0.581	$0.362	$0.509	$0.000
17	Total variance (Sch 12B, pg 1, ln 15) * (Sch 2B, ln 29)	(705)	(24,254)	6,913	(147,444)	0
18	Dollars to be refunded ((ln 7) * Sch 2B, ln 25)	0	0	0	0	0
19	Other non-demand gas costs (ln 4, col B - ln 2, col B) * (Sch 2B, ln 25)	65,709	12,918,617	255,256	5,114,898	0
20	Total monthly non-demand costs to be recovered through Gas Supply Charge (ln 17 - ln 18 + ln 19)	$65,004	$12,894,363	$262,169	$4,967,454	$0
21	Sales subject to GCA - Dth (Schedule 2B, ln 3)	20,025	3,936,578	77,783	1,558,623	0
22	Total monthly non-demand costs per unit sales (ln 20 / ln 21)	$3.246	$3.276	$3.371	$3.187	$0.000
23	Net Write-Off Recovery Cost (Sch 1C, pg 3 ln 4)	0.051	0.056	0.008	0.013	0.000
24	PEPL Unnominated Quantites Retail Cost (Sch 4, pg 3 ln 8)	0.109	0.130	0.028	0.117	0.000
25	PEPL Balancing Cost for Gas Rates D1 & D2 only (Sch 4, pg 3, ln 15)	0.011	0.011	-	-	-
26	Gas Supply Charge to be recovered through GCA (ln 16 + ln 22 + ln 23 + ln 24 + ln 25)	$3.926	$4.054	$3.769	$3.826	$0.000

Citizens Gas
Determination of Balancing Demand Charge per Unit (Dth)
Estimated For the Period February 2024
To Be Applied to the February 2024 Throughput

Line No.		A Gas Rate No. D3/No. D7	B Gas Rate No. D4	C Gas Rate No. D5	D Gas Rate No. D9
	Calculation of Balancing Demand Charge per Unit (Dth)				
27	Balancing Demand Cost Variance (Sch12B, pg. 2, ln 13 * Sch 2C, ln 24)	($2,269)	($12,551)	$755	$4,537
28	Throughput excluding Basic - Dth (Sch 2C, ln 3)	252,431	2,241,375	261,688	26,544
29	Total Balancing Demand Cost variance per unit of throughput (ln 28 / ln 29)	(0.009)	(0.006)	0.003	0.171
30	Monthly balancing demand charge per unit of throughput (Sch 1A, pg 3, ln 11)	0.005	0.005	0.005	0.005
31	PEPL balancing demand charge per unit of throughput (Sch 4, pg 3, ln 15)	0.011	0.011	0.011	0.011
32	Total balancing demand charge per unit of throughput (ln 29 + ln 30 + ln 31)	0.007	0.010	0.019	0.187

Citizens Gas
Determination of Basic Balancing Charge
Estimated for February 2024
To Be Applied to February 2024

Line No.		A Gas Rate No. D3/No. D7	B Gas Rate No. D4	C Gas Rate No. D5	D Gas Rate No. D9
	Calculation of Basic Balancing Charge per unit (Dth)				
33	Basic Balancing Charge per unit ((Sch 1, ln 29 + ln 30 + ln 31) * .05)	0.000	0.001	0.001	0.009

Citizens Gas
Determination of Back-up Gas Supply Charge
Estimated for February 2024
To Be Applied to February 2024

Line No.		
	Calculation of Back-up Gas Supply Charge per unit (Dth)	
34	PEPL retail demand costs for Gas Rate Nos. D3 & D4 (Sch 4, pg 3, ln 2)	$155,396
35	Monthly retail demand costs for Gas Rate Nos. D3 & D4 (Sch 1A, pg 3, ln 6)	821,556
36	Total retail demand costs for Gas Rates Nos. D3 & D4 (ln 34 + ln 35)	$976,952
37	Estimated monthly retail sales Dths for Gas Rates D3 & D4 (Sch. 2B, line 3)	1,636,406
38	Back-up supply capacity charge per unit (ln 36 / ln 37)	$0.597
39	PEPL monthly variable costs for Gas Rate Nos. D3 & D4 (Sch 4, pg 3, ln 5)	$28,880
40	Total monthly non-demand costs for Gas Rate Nos. D3 & D4 (Sch 1, ln 19 - ln 18)	5,370,154
41	Total retail non-demand costs for Gas Rates Nos. D3 & D4 (ln 39 + ln 40)	$5,399,034
42	Estimated monthly retail sales Dths for Gas Rates D3 & D4 (Sch. 2B, ln 3)	1,636,406
43	Back-up supply commodity charge per unit (ln 41 / ln 42)	$3.299
44	Total Back-up Gas Supply Charge (ln 38 + ln 43)	$3.896

Citizens Gas
Allocation of Monthly Demand Cost
December 2023

Line No.	Calculation of Demand Cost per Unit	A Gas Rate No. D1	B Gas Rate No. D2	C Gas Rate No. D3/No. D7	D Gas Rate No. D4	E Gas Rate No. D5	F Gas Rate No. D9	G Total
1	Retail Peak day demand allocation factors Cause No. 37399 GCA 140	0.003153	0.740425	0.006293	0.250129	-	-	1.000000
2	Retail Throughput demand allocation factors Cause No. 37399 GCA 140	0.003754	0.705611	0.019399	0.271236	-	-	1.000000
3	Peak day / Throughput allocation factors (ln 1 * 79%) + (ln 2 * 21%)	0.003279	0.733115	0.009045	0.254561	-	-	1.000000
4	Monthly retail demand costs (ln 17 * ln 3)	$7,802	$1,744,409	$21,522	$605,714	-	-	$2,379,447
5	Monthly TGT Unnom. demand costs - retail (ln 18 * 90%) * ln 3)	1,185	264,980	3,269	92,010	-	-	361,444
6	Total monthly retail demand costs (ln 4 + ln 5)	$8,987	$2,009,389	$24,791	$697,724	-	-	$2,740,891
7	Estimated monthly retail sales- Dth (Sch 2B, ln 1)	18,155	3,306,985	94,831	1,290,473	-	-	4,710,444
8	Monthly retail demand cost per unit sales (ln 6 / ln 7)	$0.495	$0.608	$0.261	$0.541	-	-	$0.582
9	Monthly balancing demand costs (ln 18 * 10%) * (Sch. 2C, ln 18)	123	22,465	1,843	13,708	1,838	183	40,160
10	Estimated monthly total throughput excl. Basic - Dth (Sch 2C, ln 1)	18,155	3,306,985	271,299	2,017,919	270,568	26,970	5,911,896
11	Monthly balancing demand cost per unit of throughput (ln 9 / ln 10)	$0.007	$0.007	$0.007	$0.007	$0.007	$0.007	$0.007

Line No.	Calculation of Monthly Demand Costs	Demand Cost
	Exelon Generation Company, LLC	
12	Nominated Demand Costs	$ 1,052,323
13	TGT Unnominated Demand Costs	$ 401,604
14	IMGPA Prepay Demand Costs	$ -
15	Demand Cost (Sch 3 ln 15 col G)	$ 293,490
16	Demand Cost (Sch 5 ln 3 col G)	$ 1,033,634
17	Monthly retail demand costs (ln 12 + sum(ln14 + ln15 + ln16))	$ 2,379,447
18	Unnominated Demand Costs (ln 13)	$401,604
19	Total monthly demand costs (ln 17 + ln 18)	$2,781,051

Citizens Gas
Allocation of Monthly Demand Cost
January 2024

Line No.	Calculation of Demand Cost per Unit	A Gas Rate No. D1	B Gas Rate No. D2	C Gas Rate No. D3/No. D7	D Gas Rate No. D4	E Gas Rate No. D5	F Gas Rate No. D9	G Total
1	Retail Peak day demand allocation factors Cause No. 37399 GCA 140	0.003153	0.740425	0.006293	0.250129	-	-	1.000000
2	Retail Throughput demand allocation factors Cause No. 37399 GCA 140	0.003754	0.705611	0.019399	0.271236	-	-	1.000000
3	Peak day / Throughput allocation factors (ln 1 * 79%) + (ln 2 * 21%)	0.003279	0.733115	0.009045	0.254561	-	-	1.000000
4	Monthly retail demand costs (ln 17 * ln 3)	$8,661	$1,936,416	$23,891	$672,385	-	-	$2,641,353
5	Monthly TGT Unnom. demand costs - retail (ln 18 * 90%) * ln 3)	1,185	264,980	3,269	92,010	-	-	361,444
6	Total monthly retail demand costs (ln 4 + ln 5)	$9,846	$2,201,396	$27,160	$764,395	-	-	$3,002,797
7	Estimated monthly retail sales- Dth (Sch 2B, ln 2)	23,596	3,753,038	91,160	1,405,082	-	-	5,272,876
8	Monthly retail demand cost per unit sales (ln 6 / ln 7)	$0.417	$0.587	$0.298	$0.544	-	-	$0.569
9	Monthly balancing demand costs (ln 18 * 10%) * (Sch. 2C, ln 19)	144	22,879	1,654	13,554	1,759	170	40,160
10	Estimated monthly total throughput - Dth (Sch 2C, ln 2)	23,596	3,753,038	271,348	2,223,296	288,486	27,838	6,587,602
11	Monthly balancing demand cost per unit of throughput (ln 9 / ln 10)	$0.006	$0.006	$0.006	$0.006	$0.006	$0.006	$0.006

Line No.	Calculation of Monthly Demand Costs	Demand Cost
	Exelon Generation Company, LLC	
12	Nominated Demand Costs	$ 1,052,323
13	TGT Unnominated Demand Costs	$ 401,604
14	IMGPA Prepay Demand Costs	$ -
15	Demand Cost (Sch 3 ln 15 col G)	$ 293,491
16	Demand Cost (Sch 5 Ln 6 Col G)	$ 1,295,539
17	Monthly retail demand costs (ln 12 + sum(ln 14 + ln15 + ln16))	$ 2,641,353
18	Unnominated Demand Costs (ln 13)	$401,604
19	Total Monthly demand costs (ln 17 + ln 18)	$ 3,042,957

Citizens Gas
Allocation of Monthly Demand Cost
February 2024

Line No.	Calculation of Demand Cost per Unit	A Gas Rate No. D1	B Gas Rate No. D2	C Gas Rate No. D3/No. D7	D Gas Rate No. D4	E Gas Rate No. D5	F Gas Rate No. D9	G Total
1	Retail Peak day demand allocation factors Cause No. 37399 GCA 140	0.003153	0.740425	0.006293	0.250129	-	-	1.000000
2	Retail Throughput demand allocation factors Cause No. 37399 GCA 140	0.003754	0.705611	0.019399	0.271236	-	-	1.000000
3	Peak day / Throughput allocation factors (ln 1 * 79%) + (ln 2 * 21%)	0.003279	0.733115	0.009045	0.254561	-	-	1.000000
4	Monthly retail demand costs (ln 17 * ln 3)	$9,149	$2,045,494	$25,237	$710,261	-	-	$2,790,141
5	Monthly TGT Unnom. demand costs - retail (ln 18 * 90%) * ln 3)	1,070	239,337	2,953	83,105	-	-	326,465
6	Total monthly retail demand costs (ln 4 + ln 5)	$10,219	$2,284,831	$28,190	$793,366	-	-	$3,116,606
7	Estimated monthly retail sales- Dth (Sch 2B, ln 3)	20,025	3,936,578	77,783	1,558,623	-	-	5,593,009
8	Monthly retail demand cost per unit sales (ln 6 / ln 7)	$0.510	$0.580	$0.362	$0.509	-	-	$0.557
9	Monthly balancing demand costs (ln 18 * 10%) * (Sch. 2C, ln 20)	108	21,190	1,359	12,065	1,409	143	36,274
10	Estimated monthly total throughput - Dth (Sch 2C, ln 3)	20,025	3,936,578	252,431	2,241,375	261,688	26,544	6,738,641
11	Monthly balancing demand cost per unit of throughput (ln 9 / ln 10)	$0.005	$0.005	$0.005	$0.005	$0.005	$0.005	$0.005

Line No.	Calculation of Monthly Demand Costs	Demand Cost
	Exelon Generation Company, LLC	
12	Nominated Demand Costs	$ 998,764
13	TGT Unnominated Demand Costs	$ 362,739
14	IMGPA Prepay Demand Costs	$ -
15	Demand Cost (Sch 3 ln 15 col G)	$ 293,490
16	Demand Cost (Sch 5 Ln 9 Col G)	$ 1,497,887
17	Monthly retail demand costs (ln 12 + sum(ln 14 + ln15 + ln16))	$ 2,790,141
18	Unnominated Demand Costs (ln 13)	$362,739
19	Total Monthly demand costs (ln 17 + ln 18)	$3,152,880

Citizens Gas
Determination of Gas Cost Adjustment (GCA)
Estimation Period December 1, 2023 through February 29, 2024
UAF Component in Rates ($/DTH)

Line No.		A December 2023	B January 2024	C February 2024	D Total
1	Volume of pipeline gas purchases (Sch. 3) - Dths	2,524,393	2,528,251	2,400,432	7,453,076
2	Volume of Gas (injected into) withdrawn from storage (See Schedule 3B) - Dths	2,264,461	2,835,308	3,288,412	8,388,181
3	Total volume supplied - Dths	4,788,854	5,363,559	5,688,844	15,841,257
4	Less: Gas Division usage - Dths	(14,622)	(19,239)	(20,059)	(53,920)
5	Total volume of gas available for sale - Dths (ln 3 + ln 4)	4,774,232	5,344,320	5,668,785	15,787,337
6	UAF Percentage 1.350%	1.350%	1.350%	1.350%	
7	UAF Volumes - Dths (ln 5 * ln 6)	64,452	72,148	76,529	213,129
8	Average Commodity Rate - Schedule 3A	$3.1996	$3.5074	$3.3720	
9	UAF Costs (ln7 * ln8)	$206,221	$253,052	$258,056	$717,329
10	Schedule 2B Retail sales volumes	4,710,444	5,272,876	5,593,009	15,576,329
11	UAF Component in rates - $ per Dth (ln9 / ln10) 1/	$0.0438	$0.0480	$0.0461	

1/ For informational purposes only.

Citizens Gas
Allocation of Net Write-Off Recovery Cost
December 2023

Line No.	Calculation of Net Write-Off Recovery Cost per Unit (Dth)	A Gas Rate No. D1	B Gas Rate No. D2	C Gas Rate No. D3/No. D7	D Gas Rate No. D4	E Gas Rate No. D5	F Total
1	Net Write-Off Recovery allocation factors Cause No. 43975	0.004201	0.908991	0.002576	0.083537	0.000695	1.000000
2	Net Write-Off Recovery cost (Sch. 1, ln 9) * ln 1	$857	$185,325	$525	$17,032	$142	$203,881
3	Estimated retail sales- Dth (Sch 2B, ln 1)	18,155	3,306,985	94,831	1,290,473	0	4,710,444
4	Net Write-Off Recovery cost per unit sales (ln 2 / ln 3)	$0.047	$0.056	$0.006	$0.013	$0.000	

Citizens Gas
Allocation of Net Write-Off Recovery Cost
January 2024

Line No.	Calculation of Net Write-Off Recovery Cost per Unit (Dth)	A Gas Rate No. D1	B Gas Rate No. D2	C Gas Rate No. D3/No. D7	D Gas Rate No. D4	E Gas Rate No. D5	F Total
1	Net Write-Off Recovery allocation factors Cause No. 43975	0.004201	0.908991	0.002576	0.083537	0.000695	1.000000
2	Net Write-Off Recovery cost (Sch. 1, ln 9) * ln 1	$988	$213,677	$606	$19,637	$163	$235,071
3	Estimated retail sales- Dth (Sch 2B, ln 2)	23,596	3,753,038	91,160	1,405,082	0	5,272,876
4	Net Write-Off Recovery cost per unit sales (ln 2 / ln 3)	$0.042	$0.057	$0.007	$0.014	$0.000	

Citizens Gas
Allocation of Net Write-Off Recovery Cost
February 2024

Line No.	Calculation of Net Write-Off Recovery Cost per Unit (Dth)	A Gas Rate No. D1	B Gas Rate No. D2	C Gas Rate No. D3/No. D7	D Gas Rate No. D4	E Gas Rate No. D5	F Total
1	Net Write-Off Recovery allocation factors Cause No. 43975	0.004201	0.908991	0.002576	0.083537	0.000695	1.000000
2	Net Write-Off Recovery cost (Sch. 1, ln 9) * ln 1	$1,020	$220,810	$626	$20,293	$169	$242,918
3	Estimated retail sales- Dth (Sch 2B, ln 3)	20,025	3,936,578	77,783	1,558,623	0	5,593,009
4	Net Write-Off Recovery cost per unit sales (ln 2 / ln 3)	$0.051	$0.056	$0.008	$0.013	$0.000	

Citizens Gas
Estimated Total Throughput for Twelve Months Ending November 2024

Line No.		A Gas Rate No. D1	B Gas Rate No. D2	C Gas Rate No. D3/No. D7	D Gas Rate No. D4	E Gas Rate No. D5	F Gas Rate No. D9	G Total Throughput Subject to GCA
	Estimated Total Throughput Volumes (Dth) for Twelve Months Ending November 2024							
1	December 2023	18,155	3,306,985	281,591	2,024,801	406,410	589,744	6,627,686
2	January 2024	23,596	3,753,038	281,144	2,230,612	434,434	828,689	7,551,513
3	February 2024	20,025	3,936,578	263,015	2,248,039	392,560	779,013	7,639,230
4	First Quarter	61,776	10,996,601	825,750	6,503,452	1,233,404	2,197,446	21,818,429
5	March 2024	16,432	2,895,558	256,012	1,748,666	353,152	792,047	6,061,867
6	April 2024	9,867	1,658,884	225,154	1,008,437	287,640	747,117	3,937,099
7	May 2024	6,468	935,119	219,877	565,072	245,148	743,315	2,714,999
8	Second Quarter	32,767	5,489,561	701,043	3,322,175	885,940	2,282,479	12,713,965
9	June 2024	5,390	395,767	214,842	342,961	223,080	717,957	1,899,997
10	July 2024	3,346	304,743	228,152	336,140	220,534	732,217	1,825,132
11	August 2024	3,167	303,182	214,546	336,019	220,720	732,279	1,809,913
12	Third Quarter	11,903	1,003,692	657,540	1,015,120	664,334	2,182,453	5,535,042
13	September 2024	3,806	316,214	220,405	378,022	231,300	478,677	1,628,424
14	October 2024	4,504	614,266	235,720	647,242	279,744	690,988	2,472,464
15	November 2024	9,531	1,690,116	269,659	1,212,939	343,320	650,532	4,176,097
16	Fourth Quarter	17,841	2,620,596	725,784	2,238,203	854,364	1,820,197	8,276,985
17	Total Throughput - Dth	124,287	20,110,450	2,910,117	13,078,950	3,638,042	8,482,575	48,344,421
	Quarterly Allocation Factor							
18	First Quarter (line 4/line 17)	0.497043	0.546810	0.283751	0.497246	0.339029	0.259053	0.451312
19	Second Quarter (line 8/line 17)	0.263640	0.272971	0.240899	0.254009	0.243521	0.269079	0.262987
20	Third Quarter (line 12/line 17)	0.095770	0.049909	0.225950	0.077615	0.182608	0.257287	0.114492
21	Fourth Quarter (line 16/line 17)	0.143547	0.130310	0.249400	0.171130	0.234842	0.214581	0.171209
	Current Throughput Allocation Factor							
22	Allocation of December 2023 Estimated Throughput (line 1/line 1, column G)	0.002739	0.498966	0.042487	0.305506	0.061320	0.088982	1.000000
23	Allocation of January 2024 Estimated Throughput (line 2/line 2, column G)	0.003125	0.496992	0.037230	0.295386	0.057529	0.109738	1.000000
24	Allocation of February 2024 Estimated Throughput (line 3/line 3, column G)	0.002621	0.515311	0.034430	0.294276	0.051387	0.101975	1.000000
25	Allocation of Quarter Estimated Throughput (line 4/line 4, column G)	0.002831	0.504006	0.037846	0.298072	0.056530	0.100715	1.000000
	Monthly Allocation Factors							
26	December 2023 (line 1/line 4)	0.293884	0.300728	0.341012	0.311342	0.329502	0.268377	0.303766
27	January 2024 (line 2/line 4)	0.381961	0.341291	0.340471	0.342989	0.352224	0.377115	0.346107
28	February 2024 (line 3/line 4)	0.324155	0.357981	0.318517	0.345669	0.318274	0.354508	0.350127
29	Total Throughput Allocation Factor (line 17/line 17, col. G)	0.002571	0.415982	0.060196	0.270537	0.075253	0.175461	1.000000

Citizens Gas
Estimated Retail Sales Volume for Twelve Months Ending November 2024

Line No.		A Gas Rate No. D1	B Gas Rate No. D2	C Gas Rate No. D3/No. D7	D Gas Rate No. D4	E Gas Rate No. D5	F Total Retail Sales Subject to GCA
	Estimated Retail Sales Volumes (Dth) for Twelve Months Ending November 2024						
1	December 2023	18,155	3,306,985	94,831	1,290,473	0	4,710,444
2	January 2024	23,596	3,753,038	91,160	1,405,082	0	5,272,876
3	February 2024	20,025	3,936,578	77,783	1,558,623	0	5,593,009
4	First Quarter	61,776	10,996,601	263,774	4,254,178	0	15,576,329
5	March 2024	16,432	2,895,558	75,266	1,187,194	0	4,174,450
6	April 2024	9,867	1,658,884	51,854	659,777	0	2,380,382
7	May 2024	6,468	935,119	51,469	354,334	0	1,347,390
8	Second Quarter	32,767	5,489,561	178,589	2,201,305	0	7,902,222
9	June 2024	5,390	395,767	48,922	204,001	0	654,080
10	July 2024	3,346	304,743	62,534	205,258	0	575,881
11	August 2024	3,167	303,182	48,928	204,517	0	559,794
12	Third Quarter	11,903	1,003,692	160,384	613,776	0	1,789,755
13	September 2024	3,806	316,214	53,525	212,182	0	585,727
14	October 2024	4,504	614,266	59,536	308,260	0	986,566
15	November 2024	9,531	1,690,116	85,997	657,075	0	2,442,719
16	Fourth Quarter	17,841	2,620,596	199,058	1,177,517	0	4,015,012
17	Total Retail Sales - Dth	124,287	20,110,450	801,805	8,246,776	0	29,283,318
	Quarterly Retail Allocation Factor						
18	First Quarter (line 4/line 17)	0.497043	0.546810	0.328975	0.515860	0.000000	0.531918
19	Second Quarter (line 8/line 17)	0.263640	0.272971	0.222734	0.266929	0.000000	0.269854
20	Third Quarter (line 12/line 17)	0.095770	0.049909	0.200029	0.074426	0.000000	0.061119
21	Fourth Quarter (line 16/line 17)	0.143547	0.130310	0.248262	0.142785	0.000000	0.137109
22	Annual (line 17 / line 17, Column F)	0.004244	0.686755	0.027381	0.281620	0.000000	1.000000
	Current Retail Sales Allocation Factor						
23	Allocation of December 2023 Estimated Throughput (line 1/line 1, column F)	0.003854	0.702054	0.020132	0.273960	0.000000	1.000000
24	Allocation of January 2024 Estimated Throughput (line 2/line 2, column F)	0.004475	0.711763	0.017288	0.266474	0.000000	1.000000
25	Allocation of February 2024 Estimated Throughput (line 3/line 3, column F)	0.003580	0.703840	0.013907	0.278673	0.000000	1.000000
26	Allocation of Quarter Estimated Retail Sales (line 4/line 4, column F)	0.003966	0.705982	0.016934	0.273118	0.000000	1.000000
	Monthly Retail Allocation Factors						
27	December 2023 (line 1/line 4)	0.293884	0.300728	0.359516	0.303342	0.000000	0.302410
28	January 2024 (line 2/line 4)	0.381961	0.341291	0.345599	0.330283	0.000000	0.338519
29	February 2024 (line 3/line 4)	0.324155	0.357981	0.294885	0.366375	0.000000	0.359071

Citizens Gas
Estimated Total Throughput Excluding Basic Volume (Dth) for Twelve Months Ending November 2024

		A	B	C	D	E	F	G
Line No.		Gas Rate No. D1	Gas Rate No. D2	Gas Rate No. D3/No. D7	Gas Rate No. D4	Gas Rate No. D5	Gas Rate No. D9	Total Throughput Subject to GCA
	Estimated Total Throughput Excluding Basic Volumes (Dth) for Twelve Months Ending November 2024							
1	December 2023	18,155	3,306,985	271,299	2,017,919	270,568	26,970	5,911,896
2	January 2024	23,596	3,753,038	271,348	2,223,296	288,486	27,838	6,587,602
3	February 2024	20,025	3,936,578	252,431	2,241,375	261,688	26,544	6,738,641
4	First Quarter	61,776	10,996,601	795,078	6,482,590	820,742	81,352	19,238,139
5	March 2024	16,432	2,895,558	244,728	1,742,528	236,530	25,296	5,161,072
6	April 2024	9,867	1,658,884	212,674	1,003,277	194,640	23,220	3,102,562
7	May 2024	6,468	935,119	206,609	560,484	167,462	21,886	1,898,028
8	Second Quarter	32,767	5,489,561	664,011	3,306,289	598,632	70,402	10,161,662
9	June 2024	5,390	395,767	201,162	338,701	153,360	21,180	1,115,560
10	July 2024	3,346	304,743	214,450	331,924	151,714	21,080	1,027,257
11	August 2024	3,167	303,182	200,844	331,803	151,838	21,080	1,011,914
12	Third Quarter	11,903	1,003,692	616,456	1,002,428	456,912	63,340	3,154,731
13	September 2024	3,806	316,214	206,845	373,642	158,640	21,420	1,080,567
14	October 2024	4,504	614,266	222,882	642,158	189,596	22,940	1,696,346
15	November 2024	9,531	1,690,116	258,027	1,206,939	230,220	24,960	3,419,793
16	Fourth Quarter	17,841	2,620,596	687,754	2,222,739	578,456	69,320	6,196,706
17	Total Throughput excl. Basic - Dth	124,287	20,110,450	2,763,299	13,014,046	2,454,742	284,414	38,751,238
	Current Throughput Excl. Basic Allocation Factor							
18	Allocation of December 2023 Estimated Throughput (line 1/line 1, column G)	0.003071	0.559378	0.045890	0.341332	0.045767	0.004562	1.000000
19	Allocation of January 2024 Estimated Throughput (line 2/line 2, column G)	0.003582	0.569712	0.041191	0.337497	0.043792	0.004226	1.000000
20	Allocation of February 2024 Estimated Throughput (line 3/line 3, column G)	0.002972	0.584180	0.037460	0.332615	0.038834	0.003939	1.000000
21	Total Throughput Excl. Basic Allocation Factor (line 17/line 17, col. G)	0.003207	0.518963	0.071309	0.335836	0.063346	0.007339	1.000000
	Monthly Total Throughput less Basic							
22	December 2023 (line 1/line 4)	0.293884	0.300728	0.341223	0.311283	0.329663	0.331522	0.307301
23	January 2024 (line 2/line 4)	0.381961	0.341291	0.341285	0.342964	0.351494	0.342192	0.342424
24	February 2024 (line 3/line 4)	0.324155	0.357981	0.317492	0.345753	0.318843	0.326286	0.350275

Citizens Gas
Purchased Gas Cost - Estimated
December 2023

		A	B	C	D	E	F	G	H	I	J
		Estimated Purchases			Supplier Rates Estimated			Estimated Costs			
			Commodity								
Line No.	Month and Supplier	Demand	MCF	DTH	Demand $/DTH	Commodity $/DTH	Other $/MCF	Demand (A x D)	Commodity (C x E)	Other	Total (G+H+I)
	December 2023										
	Exelon Generation Company, LLC										
1	Panhandle Eastern Pipeline - TOR			-		$3.5694			-		-
2	Texas Gas Transmission - TOR			342,130		3.2945			1,127,147		1,127,147
3	TGT-REX			-		3.7096			-		-
4	Indiana Municipal Gas Purchasing Authority - TOR			-		3.5694			-		-
5	Indiana Municipal Gas Purchasing Authority - Prepay			-		3.2436			-		-
6	PEAK B			310,000		3.2285			1,000,835		1,000,835
7	Rockies Express Pipeline - TOR			620,000		2.9485			1,828,070		1,828,070
8	PEAK A			310,000		3.1560			978,360		978,360
9	Midwestern Gas Transmission Purchases			-		3.6973			-		-
10	Fixed Price Purchases								-		-
11	Hedging Transaction Costs								322,835		322,835
12	Boil-off / Peaking purchase			42,263		3.4360			145,216		145,216
13	Net Demand Cost Charges - AMA							1,453,927	-		1,453,927
14	Demand Cost Charges -IMGPA - Prepay	-			-			-	-		-
15	Texas Gas - NNS - (Injections)/Withdrawls			900,000	0.3261	2.9719		293,490	2,674,710		2,968,200
16	Total			2,524,393				$1,747,417	$8,077,173	-	$9,824,590

Citizens Gas
Purchased Gas Cost - Estimated
January 2024

		A	B	C	D	E	F	G	H	I	J
		Estimated Purchases			Supplier Rates Estimated			Estimated Costs			
			Commodity								
Line No.	Month and Supplier	Demand	MCF	DTH	Demand $/DTH	Commodity $/DTH	Other $/MCF	Demand (A x D)	Commodity (C x E)	Other	Total (G+H+I)
	January 2024										
	Exelon Generation Company, LLC										
1	Panhandle Eastern Pipeline - TOR			-		$4.6083			-		-
2	Texas Gas Transmission - TOR			345,986		3.6545			1,264,406		1,264,406
3	TGT-REX			-		4.3886			-		-
4	Indiana Municipal Gas Purchasing Authority - TOR			-		4.6083			-		-
5	Indiana Municipal Gas Purchasing Authority - Prepay			-		4.2825			-		-
6	PEAK B			310,000		3.4765			1,077,715		1,077,715
7	Rockies Express Pipeline - TOR			620,000		3.4712			2,152,144		2,152,144
8	PEAK A			310,000		3.4040			1,055,240		1,055,240
9	Midwestern Gas Transmission Purchases			-		4.3746			-		-
10	Fixed Price Purchases								-		-
11	Hedging Transaction Costs								487,616		487,616
12	Boil-off / Peaking purchase			42,263		3.6840			155,697		155,697
13	Net Demand Cost Charges - AMA							1,453,927	-		1,453,927
14	Demand Cost Charges -IMGPA - Prepay	-			-			-	-		-
15	Texas Gas - NNS - (Injections)/Withdrawls			900,002	0.3261	2.9719		293,491	2,674,716		2,968,207
16	Total			2,528,251				$1,747,418	$8,867,534	-	$10,614,952

Citizens Gas
Purchased Gas Cost - Estimated
February 2024

		A	B	C	D	E	F	G	H	I	J
		Estimated Purchases			Supplier Rates Estimated			Estimated Costs			
			Commodity								
Line No.	Month and Supplier	Demand	MCF	DTH	Demand $/DTH	Commodity $/DTH	Other $/MCF	Demand (A x D)	Commodity (C x E)	Other	Total (G+H+I)
	February 2024										
	Exelon Generation Company, LLC										
1	Panhandle Eastern Pipeline - TOR			-		$4.5406			-		-
2	Texas Gas Transmission - TOR			318,168		3.6200			1,151,768		1,151,768
3	TGT-REX			-		4.3188			-		-
4	Indiana Municipal Gas Purchasing Authority - TOR			-		4.5406			-		-
5	Indiana Municipal Gas Purchasing Authority - Prepay			-		4.2148			-		-
6	PEAK B			280,000		3.4025			952,700		952,700
7	Rockies Express Pipeline - TOR			580,000		3.4261			1,987,138		1,987,138
8	PEAK A			280,000		3.3300			932,400		932,400
9	Midwestern Gas Transmission Purchases			-		4.3049			-		-
10	Fixed Price Purchases										
11	Hedging Transaction Costs								243,066		243,066
12	Boil-off / Peaking purchase			42,263		3.6100			152,569		152,569
13	Net Demand Cost Charges - AMA							1,361,503	-		1,361,503
14	Demand Cost Charges -IMGPA - Prepay	-			-			-	-		-
15	Texas Gas - NNS - (Injections)/Withdrawls			900,001	0.3261	2.9719		293,490	2,674,713		2,968,203
16	Total			2,400,432				$1,654,993	$8,094,354	-	$9,749,347

Citizens Gas
Calculation of the Projected Average Pipeline Rates
Non-pipeline Supplies, Storage Injections, and Company Usage

Line No	Description	Dec 2023	Jan 2024	Feb 2024	Total
	Commodity Volumes (Dth)				
	Purchases for Retail:				
1	Panhandle TOR	0	0	0	0
2	IMGPA TOR	0	0	0	0
3	IMGPA Prepay	0	0	0	0
4	Midwestern Gas	0	0	0	0
5	Rockies Express TOR - Monthly	620,000	620,000	580,000	1,820,000
6	PEAK A	310,000	310,000	280,000	900,000
7	Fixed Price Purchases (Sch. 3)	0	0	0	0
8	Texas Gas TOR	342,130	345,986	318,168	1,006,284
9	TGT-Rex East	0	0	0	0
10	PEAK B	310,000	310,000	280,000	900,000
11	Texas Gas NNS	900,000	900,002	900,001	2,700,003
12	Boil-off/ Peaking purchases (Sch. 3)	42,263	42,263	42,263	126,789
	Total Retail Volumes				
13	(Ln1 through Ln12)	2,524,393	2,528,251	2,400,432	7,453,076
	Demand Rate				
14	Total Demand Costs (Sch. 3)	$1,747,417	$1,747,418	$1,654,993	$5,149,828
15	Demand Cost per Dth (Line 14 / Line 13)	$0.6922	$0.6912	$0.6895	$0.6910
	Commodity Rate				
16	Panhandle TOR	$3.5694	$4.6083	$4.5406	
17	IMGPA TOR	3.5694	4.6083	4.5406	
18	IMGPA Prepay	3.2436	4.2825	4.2148	
19	Annual Delivery Service - Midwestern Gas	3.6973	4.3746	4.3049	
20	Rockies Express TOR - Monthly	2.9485	3.4712	3.4261	
21	PEAK A	3.1560	3.4040	3.3300	
22	Fixed Price Purchases (Sch. 3)	0.0000	0.0000	0.0000	
23	Texas Gas TOR	3.2945	3.6545	3.6200	
24	TGT-Rex East	3.7096	4.3886	4.3188	
25	Texas Gas NNS	2.9719	2.9719	2.9719	
26	Boil-off/ Peaking purchases (Sch. 3)	3.4360	3.6840	3.6100	
27	PEAK B	3.2285	3.4765	3.4025	
	Commodity Costs				
28	PEPL (Ln 1 x Ln 16)	$0	$0	$0	$0
29	IMGPA - TOR (Ln 2 x Ln 17)	0	0	0	0
30	IMGPA - Authority Prepay (Ln 3 x Ln 18)	0	0	0	0
31	Midwestern (Ln 4 x Ln 19)	0	0	0	0
32	Rockies Express TOR (Ln 5 X Ln 20)	1,828,070	2,152,144	1,987,138	5,967,352
33	PEAK A (Ln 6 X Ln 21)	978,360	1,055,240	932,400	2,966,000
34	Fixed Price Purchases (Ln 7 x Ln 22)	0	0	0	0
35	Texas Gas (Ln 8 x Ln 23)	1,127,147	1,264,406	1,151,768	3,543,321
36	TGT-Rex East (Ln 9 x Ln 24)	0	0	0	0
37	Texas Gas -Unnominated Gas (Ln 11 x Ln 25)	2,674,710	2,674,716	2,674,713	8,024,139
38	Boil-off/ Peaking purchases (Ln 12 x Ln 26)	145,216	155,697	152,569	453,482
39	PEAK B (Ln 10 x Ln 27)	1,000,835	1,077,715	952,700	3,031,250
40	Hedging Transaction Costs (Sch 3)	322,835	487,616	243,066	1,053,517
41	Subtotal(Ln 28 through Ln 40)	$8,077,173	$8,867,534	$8,094,354	$25,039,061
	Commodity Cost per Dth				
42	(Line 41/Line 13)	$3.1996	$3.5074	$3.3720	$3.3596
	Total Average Rate per Dth				
43	(Line 15 + Line 42)	$3.8918	$4.1986	$4.0615	$4.0506

Citizens Gas
Projected Information
For Three Months Ending February 29, 2024

Line No.	A Dec 2023	B Volumes in Dths		C Commodity Cost per Dth	D % of Total	E Reference
1	Fixed Price Purchases	-	$	-	0.00%	Sch 3 pg 1 line 10
2	Monthly Spot Market - Index Purchases	1,582,130	$	3.3229	33.04%	Sch 3 pg 1 (line 16 - line 10 - line 12 - line 15)
3	Boil off/Peaking Purchases	42,263	$	3.4360	0.88%	Sch 3 pg 1 line 12
4	Unnominated Seasonal Gas Purchases	900,000	$	2.9719	18.79%	Sch 3 pg 1 line 15
5	Storage Withdrawal - Net	2,264,461	$	3.0801	47.29%	Sch 5 ln 3 col B - Sch 4pg 1 ln 22 Col E
6	Storage Injection - Gross	-	$	-	0.00%	Sch 5 ln 3 col A - Sch 4 pg 1 ln 20 Col E
7	Total Net Purchases	4,788,854			100.00%	

	Jan 2024	Volumes in Dths		Commodity Cost per Dth	% of Total	
8	Fixed Price Purchases	-	$	-	0.00%	Sch 3 pg 2 line 10
9	Monthly Spot Market - Index Purchases	1,585,986	$	3.8065	29.57%	Sch 3 pg 2 (line 16 - line 10 - line 12 - line 15)
10	Boil off/Peaking Purchases	42,263	$	3.6840	0.79%	Sch 3 pg 2 line 12
11	Unnominated Seasonal Gas Purchases	900,002	$	2.9719	16.78%	Sch 3 pg 2 line 15
12	Storage Withdrawal - Net	2,835,308	$	3.0744	52.86%	Sch 5 line 6 col B - Sch 4pg 2 ln 22 Col E
13	Storage Injection - Gross	-	$	-	0.00%	Sch 5 line 6 col A - Sch 4 pg 2 ln 20 Col E
14	Total Net Purchases	5,363,559			100.00%	

	Feb 2024	Volumes in Dths		Commodity Cost per Dth	% of Total	
15	Fixed Price Purchases	-	$	-	0.00%	Sch 3 pg 3 line 10
16	Monthly Spot Market - Index Purchases	1,458,168	$	3.6121	25.63%	Sch 3 pg 3 (line 16 - line 10 - line 12 - line 15)
17	Boil off/Peaking Purchases	42,263	$	3.6100	0.74%	Sch 3 pg 3 line 12
18	Unnominated Seasonal Gas Purchases	900,001	$	2.9719	15.82%	Sch 3 pg 3 line 15
19	Storage Withdrawal - Net	3,288,412	$	3.0923	57.81%	Sch 5 line 9 col B - Sch 4pg 3 ln 22 Col E
20	Storage Injection - Gross	-	$	-	0.00%	Sch 5 line 9 col A - Sch 4 pg 3 ln 20 Col E
21	Total Net Purchases	5,688,844			100.00%	

Citizens Gas
Allocation of Panhandle Unnominated Quantities Cost
December 2023

Ln. No.	Calc. of PEPL Unnom.Costs / Unit	Gas Rate No. D1	Gas Rate No. D2	Gas Rate No. D3/No. D7	Gas Rate No. D4	Gas Rate No. D5	Gas Rate No. D9	Total
1	Retail seasonal demand allocation factor Cause No. 37399 GCA 140	0.003122	0.733268	0.003164	0.260446	0.000000	-	1.000000
2	PEPL retail demand costs (ln 17 * ln 1)	$1,953	$458,628	$1,979	$162,898	$0	-	$625,458
3	Estimated monthly retail sales- Dth (Sch 2B, ln 1)	18,155	3,306,985	94,831	1,290,473	0	-	4,710,444
4	Fixed cost per unit retail sales (ln 2 / ln 3)	$0.108	$0.139	$0.021	$0.126	$0.000	-	
5	PEPL monthly retail variable costs (ln 24 * ln 1)	$278	$65,270	$282	$23,183	$0	-	$89,013
6	Estimated monthly retail sales- Dth (Sch 2B, ln 1)	18,155	3,306,985	94,831	1,290,473	0	-	4,710,444
7	Net monthly retail variable costs per unit sales (ln 5 / ln 6)	$0.015	$0.020	$0.003	$0.018	$0.000	-	
8	Total PEPL cost per unit retail sales (ln 4 + ln 7)	$0.123	$0.159	$0.024	$0.144	$0.000	-	
9	PEPL balancing demand costs (ln 18 * Sch 2C, ln 18)	$190	$34,603	$2,839	$21,114	$2,831	$282	$61,859
10	Est. monthly total throughput excl. Basic - Dth (Sch 2C, ln 1)	18,155	3,306,985	271,299	2,017,919	270,568	26,970	5,911,896
11	Fixed balancing cost per unit throughput (ln 9 / ln 10)	$0.010	$0.010	$0.010	$0.010	$0.010	$0.010	
12	PEPL monthly balancing variable costs (ln 25 * Sch 2C, ln 18)	$27	$4,925	$404	$3,005	$403	$40	$8,804
13	Estimated monthly total throughput excl Basic- Dth (Sch 2C, ln 1)	18,155	3,306,985	271,299	2,017,919	270,568	26,970	5,911,896
14	Net monthly balancing variable costs per unit throughput (ln12 / ln13)	$0.001	$0.001	$0.001	$0.001	$0.001	$0.001	
15	Total PEPL Balancing cost per unit throughput (ln 11 + ln 14)	$0.011	$0.011	$0.011	$0.011	$0.011	$0.011	

Ln. No.	Calculation of Monthly Fixed Costs	A Monthly Fixed Costs
16	PEPL demand cost	$687,317
17	PEPL Retail Demand Costs (line 16 * 91%) 1/	$625,458
18	PEPL Balancing Demand Costs (line 16 * 9%) 1/	$61,859

Ln. No.	Calculation of Monthly Variable Costs	A	B	C	D	E	F	G	H	I
		Volumes		Storage Rates			Costs			
	December 2023	Inject.	W/Drl.	Inject.	W/Drl.	Comp. Fuel	Inject. (A x C)	W/Drl. (B x D)	Compressor Fuel	Total (F+G+H)
19	PEPL Injections (Net)	0		0.0020			$0			$0
20	(100 - day firm) (Midpoint)	0		0.0094		0	0		$0	0
21	PEPL Withdrawals (Gross)		1,300,000		0.0020			2,600		2,600
22	(100 - day firm) (Net)		1,276,025		0.0094	23,975		11,995	83,222	95,217
23	Total (ln 19 + ln20 + ln21 + ln22)						$0	$14,595	$83,222	$97,817
24	PEPL Retail Variable Costs (line 23 * 91%) 1/									$89,013
25	PEPL Balancing Variable Costs (line 23* 9%) 1/									$8,804

1/ Percentages from Balancing Study - 2 year average Apr., 2008 - Mar., 2010 PEPL-WSS

Citizens Gas
Allocation of Panhandle Unnominated Quantities Cost
January 2024

Ln. No.	Calc. of PEPL Unnom.Costs / Unit	Gas Rate No. D1	Gas Rate No. D2	Gas Rate No. D3/No. D7	Gas Rate No. D4	Gas Rate No. D5	Gas Rate No. D9	Total
1	Retail seasonal demand allocation factor Cause No. 37399 GCA 140	0.003122	0.733268	0.003164	0.260446	0.000000	-	1.000000
2	PEPL retail demand costs (ln 17 * ln 1)	$1,953	$458,628	$1,979	$162,898	$0	-	$625,458
3	Estimated monthly retail sales - Dth (Sch 2B, ln 2)	23,596	3,753,038	91,160	1,405,082	0	-	5,272,876
4	Fixed cost per unit retail sales (ln 2 / ln 3)	$0.083	$0.122	$0.022	$0.116	$0.000	-	
5	PEPL monthly retail variable costs (ln 24 * ln 1)	$372	$87,358	$377	$31,028	$0	-	$119,135
6	Estimated monthly retail sales - Dth (Sch 2B, ln 2)	23,596	3,753,038	91,160	1,405,082	0	-	5,272,876
7	Net monthly retail variable costs per unit sales (ln 5 / ln 6)	$0.016	$0.023	$0.004	$0.022	$0.000	-	
8	Total PEPL cost per unit retail sales (ln 4 + ln 7)	$0.099	$0.145	$0.026	$0.138	$0.000	-	
9	PEPL balancing demand costs (ln 18 * Sch 2C, ln 19)	$222	$35,242	$2,548	$20,877	$2,709	$261	$61,859
10	Estimated monthly total throughput - Dth (Sch 2C, ln 2)	23,596	3,753,038	271,348	2,223,296	288,486	27,838	6,587,602
11	Fixed balancing cost per unit throughput (ln 9 / ln 10)	$0.009	$0.009	$0.009	$0.009	$0.009	$0.009	
12	PEPL monthly balancing variable costs (ln 25 * Sch 2C, ln 19)	$42	$6,713	$485	$3,977	$516	$50	$11,783
13	Estimated monthly total throughput excl Basic - Dth (Sch 2C, ln 2)	23,596	3,753,038	271,348	2,223,296	288,486	27,838	6,587,602
14	Net monthly balancing variable costs per unit throughput (ln 12 / ln 13)	$0.002	$0.002	$0.002	$0.002	$0.002	$0.002	
15	Total PEPL Balancing cost per unit throughput (ln 11 + ln 14)	$0.011	$0.011	$0.011	$0.011	$0.011	$0.011	

Ln. No.	Calculation of Fixed Costs	A Monthly Fixed Costs
16	PEPL demand cost	$687,317
17	PEPL Retail Demand Costs (line 16 * 91%) 1/	$625,458
18	PEPL Balancing Demand Costs (line 16 * 9%) 1/	$61,859

Ln. No.	Calculation of Monthly Variable Costs	A	B	C	D	E	F	G	H	I
		Volumes		Storage Rates			Costs			
	January 2024	Inject.	W/Drl.	Inject.	W/Drl.	Comp. Fuel	Inject. (A x C)	W/Drl. (B x D)	Compressor Fuel	Total (F+G+H)
19	PEPL Injections (Net)	0		0.0020			$0			$0
20	(100 - day firm) (Midpoint)	0		0.0094		0	0		$0	0
21	PEPL Withdrawals (Gross)		1,740,000		0.0020			3,480		3,480
22	(100 - day firm) (Net)		1,707,911		0.0094	32,089		16,054	111,384	127,438
23	Total (ln 19 + ln20 + ln21 + ln22)						$0	$19,534	$111,384	$130,918
24	PEPL Retail Variable Costs (line 23 * 91%) 1/									$119,135
25	PEPL Balancing Variable Costs (line 23 * 9%) 1/									$11,783

1/ Percentages from Balancing Study - 2 year average Apr., 2008 - Mar., 2010 PEPL-WSS

Citizens Gas
Allocation of Panhandle Unnominated Quantities Cost
February 2024

Ln. No.	Calc. of PEPL Unnom.Costs / Unit	Gas Rate No. D1	Gas Rate No. D2	Gas Rate No. D3/No. D7	Gas Rate No. D4	Gas Rate No. D5	Gas Rate No. D9	Total
1	Retail seasonal demand allocation factor Cause No. 37399 GCA 140	0.003122	0.733268	0.003164	0.260446	0.000000	-	1.000000
2	PEPL retail demand costs (ln 17 * ln 1)	$1,840	$432,257	$1,865	$153,531	$0	-	$589,493
3	Estimated monthly retail sales- Dth (Sch 2B, ln 3)	20,025	3,936,578	77,783	1,558,623	0	-	5,593,009
4	Fixed cost per unit retail sales (ln 2 / ln 3)	$0.092	$0.110	$0.024	$0.099	$0.000	-	
5	PEPL monthly retail variable costs (ln 24 * ln 1)	$342	$80,331	$347	$28,533	$0	-	$109,553
6	Estimated monthly retail sales- Dth (Sch 2B, ln 3)	20,025	3,936,578	77,783	1,558,623	0	-	5,593,009
7	Net monthly retail variable costs per unit sales (ln 5 / ln 6)	$0.017	$0.020	$0.004	$0.018	$0.000	-	
8	Total PEPL cost per unit retail sales (ln 4 + ln 7)	$0.109	$0.130	$0.028	$0.117	$0.000	-	
9	PEPL balancing demand costs (ln 18* Sch 2C, ln 20)	$173	$34,058	$2,184	$19,392	$2,264	$230	$58,301
10	Estimated monthly total throughput - Dth (Sch 2C, ln 3)	20,025	3,936,578	252,431	2,241,375	261,688	26,544	6,738,641
11	Fixed balancing cost per unit throughput (ln 9 / ln 10)	$0.009	$0.009	$0.009	$0.009	$0.009	$0.009	
12	PEPL monthly balancing variable costs (ln 25 * Sch 2C, ln 20)	$32	$6,329	$406	$3,604	$421	$43	$10,835
13	Estimated monthly total throughput excl Basic - Dth (Sch 2C, ln 3)	20,025	3,936,578	252,431	2,241,375	261,688	26,544	6,738,641
14	Net monthly balancing variable costs per unit throughput (ln 12 / ln 13)	$0.002	$0.002	$0.002	$0.002	$0.002	$0.002	
15	Total PEPL Balancing cost per unit sales (ln 11 + ln 14)	$0.011	$0.011	$0.011	$0.011	$0.011	$0.011	

Ln. No.	Calculation of Fixed Costs	A Monthly Fixed Costs
16	PEPL demand cost	$647,794
17	PEPL Retail Demand Costs (line 16 * 91%) 1/	$589,493
18	PEPL Balancing Demand Costs (line 16 * 9%) 1/	$58,301

Ln. No.	Calculation of Monthly Variable Costs	A	B	C	D	E	F	G	H	I
		Volumes		Storage Rates			Costs			
	February 2024	Inject.	W/Drl.	Inject.	W/Drl.	Comp. Fuel	Inject. (A x C)	W/Drl. (B x D)	Compressor Fuel	Total (F+G+H)
19	PEPL Injections (Net)	0		0.0020			$0			$0
20	(100 - day firm) (Midpoint)	0		0.0094		0	0		$0	0
21	PEPL Withdrawals (Gross)		1,600,000		0.0020			3,200		3,200
22	(100 - day firm) (Net)		1,570,493		0.0094	29,507		14,763	102,425	117,188
23	Total (ln 19 + ln20 + ln21 + ln22)						$0	$17,963	$102,425	$120,388
24	PEPL Retail Variable Costs (line 23 * 91%) 1/									$109,553
25	PEPL & 3 Balancing Variable Costs (line 23 * 9%) 1/									$10,835

1/ Percentages from Balancing Study - 2 year average Apr., 2008 - Mar., 2010 PEPL-WSS

Citizens Gas
Estimated Cost of Gas Injections and Withdrawals
For Three Months Ending February 29, 2024

		A	B	C	D	E	F	G	H	I
		Estimated Change		Estimated Cost of Gas						
				Injections		Withdrawals		Net		
Line No.		Injections Dth	Withdrawals Dth	Demand	Commodity	Demand	Commodity	Demand	Commodity	Total
	December 2023									
1	Greene Co.	0	988,436	$0	$0	$444,994	$3,124,644	$444,994	$3,124,644	$3,569,638
2	PEPL FS	0	1,300,000	0	0	588,640	3,923,920	588,640	3,923,920	4,512,560
3	Subtotal	0	2,288,436	0	0	1,033,634	7,048,564	1,033,634	7,048,564	8,082,198
	January 2024									
4	Greene Co.	0	1,127,397	0	0	507,667	3,563,815	507,667	3,563,815	4,071,482
5	PEPL FS	0	1,740,000	0	0	787,872	5,251,842	787,872	5,251,842	6,039,714
6	Subtotal	0	2,867,397	0	0	1,295,539	8,815,657	1,295,539	8,815,657	10,111,196
	February 2024									
7	Greene Co.	0	1,717,919	0	0	773,407	5,430,686	773,407	5,430,686	6,204,093
8	PEPL FS	0	1,600,000	0	0	724,480	4,829,440	724,480	4,829,440	5,553,920
9	Subtotal	0	3,317,919	0	0	1,497,887	10,260,126	1,497,887	10,260,126	11,758,013
10	Grand Total	0	8,473,752	$0	$0	$3,827,060	$26,124,347	$3,827,060	$26,124,347	$29,951,407

Citizens Gas
Demand Allocation of Injections and Withdrawals
Greene Co.
For Three Months Ending February 29, 2024

		A	B	C	D	E	F
Line No.		Volume DTH	Demand Cost	Commodity Cost	Total Cost	Total $/DTH	Comm $/DTH
1	Beginning Balance @ December 2023	5,730,918	$2,580,219	$18,116,319	$20,696,538	$3.6114	$3.1612
2	Add: Net injections at cost	0	0	0	0	0.0000	0.0000
3	Less: Gross withdrawals - avg. unit cost	(988,436)	(444,994)	(3,124,644)	(3,569,638)	3.6114	3.1612
4	Beginning Balance @ January 2024	4,742,482	2,135,225	14,991,675	17,126,900	3.6114	3.1611
5	Add: Net injections at cost	0	0	0	0	0.0000	0.0000
6	Less: Gross withdrawals - avg. unit cost	(1,127,397)	(507,667)	(3,563,815)	(4,071,482)	3.6114	3.1611
7	Beginning Balance @ February 2024	3,615,085	1,627,558	11,427,860	13,055,418	3.6114	3.1612
8	Add: Net injections at cost	0	0	0	0	0.0000	0.0000
9	Less: Gross withdrawals - avg. unit cost	(1,717,919)	(773,407)	(5,430,686)	(6,204,093)	3.6114	3.1612
10	Ending balance @ February 29, 2024	1,897,166	$854,151	$5,997,174	$6,851,325	$3.6113	$3.1611

Citizens Gas
Demand Allocation of Injections and Withdrawals
From PEPL FS
For Three Months Ending February 29, 2024

		A	B	C	D	E	F
Line No.		Volume DTH	Demand Cost	Commodity Cost	Total Cost	Total $/DTH	Comm $/DTH
1	Beginning Balance @ December 2023	5,948,503	$2,693,523	$17,954,668	$20,648,191	$3.4712	$3.0184
2	Add: Net injections at cost	0	0	0	0	0.0000	0.0000
3	Less: Gross withdrawals - avg. unit cost	(1,300,000)	(588,640)	(3,923,920)	(4,512,560)	3.4712	3.0184
4	Beginning Balance @ January 2024	4,648,503	2,104,883	14,030,748	16,135,631	3.4711	3.0183
5	Add: Net injections at cost	0	0	0	0	0.0000	0.0000
6	Less: Gross withdrawals - avg. unit cost	(1,740,000)	(787,872)	(5,251,842)	(6,039,714)	3.4711	3.0183
7	Beginning Balance @ February 2024	2,908,503	1,317,011	8,778,906	10,095,917	3.4712	3.0184
8	Add: Net injections at cost	0	0	0	0	0.0000	0.0000
9	Less: Gross withdrawals - avg. unit cost	(1,600,000)	(724,480)	(4,829,440)	(5,553,920)	3.4712	3.0184
10	Ending balance @ February 29, 2024	1,308,503	$592,531	$3,949,466	$4,541,997	$3.4711	$3.0183

Citizens Gas
Calculation of Actual Gas Supply and Balancing Demand Cost Variance
June 2023

Line No		Gas Rate No. D1	Gas Rate No. D2	Gas Rate No. D3/No. D7	Gas Rate No. D4	Gas Rate No. D5	All GCA Classes
	Calculation of Gas Supply Variance						
1	Retail Peak day demand allocation factor Cause No. 37399 - GCA 140	0.003153	0.740425	0.006293	0.250129	0.000000	1.000000
2	Retail Throughput demand allocation factor Cause No. 37399 - GCA 140	0.003754	0.705611	0.019399	0.271236	0.000000	1.000000
3	Retail Peak day/Retail throughput demand allocation factor (ln 1 * 79%) + (ln 2 * 21%)	0.003279	0.733115	0.009045	0.254561	0.000000	1.000000
4	Normalized Retail Seasonal Demand Allocation Factor Cause No. 37399 - GCA 140	0.003122	0.733268	0.003164	0.260446	0.000000	1.000000
5	Actual net Demand cost allocated (ln 3 * Schedule 7, pg. 1, ln 1 Col A)	$2,444	$546,371	$6,741	$189,717	$0	$745,273
6	Allocated other demand costs (ln 2 * (Schedule 7, pg. 1, ln 4 Col A)	(1,926)	(361,986)	(9,952)	(139,147)	0	(513,011)
7	Allocated contracted storage costs (ln 4 * Schedule 7 pg. 1, ln 3 Col B))	1,718	403,452	1,741	143,301	0	$550,212
8	Actual other non-demand gas costs (Sch. 7 pg. 1, Col B, ln 2 + ln 4) * (Sch. 6A, ln 28))	8,809	621,132	103,507	374,560	0	1,108,008
9	Total actual cost of gas incurred (lns 5+6+7+8)	$11,045	$1,208,969	$102,037	$568,431	$0	$1,890,482
10	Actual cost of gas billed including Utility Gross Receipts Tax (Sch. 6A, ln 31)	$17,523	$1,639,282	$163,240	$974,028	$0	$2,794,073
11	Net - Write Off Recovered (Sch 12 C ln 3)	122	24,395	57	3,730	0	28,304
12	Variance from Cause No. 37399-GCA 158 Filing (Sch. 1, pg. 2 Jun., 2023 ln 17)	1,410	75,594	8,724	25,907	0	111,635
13	Refund from cause No. 37399- GCA 158 Filing (Sch. 1, pg. 2 Jun., 2023 ln 18)	0	0	0	0	0	0
14	Gas cost recovered to be reconciled with actual cost of gas incurred (ln 10 - ln 11 - ln 12 + ln 13)	15,991	1,539,293	154,459	944,391	0	2,654,134
15	Gas cost variance (over)/underrecovery (ln 9 - ln 14)	($4,946)	($330,324)	($52,422)	($375,960)	$0	($763,652)

Citizens Gas
Calculation of Actual Gas Cost Variance
June 2023

Line No		Gas Rate No. D1	Gas Rate No. D2	Gas Rate No. D3/No. D7	Gas Rate No. D4	Gas Rate No. D5	Gas Rate No. D9	All GCA Classes
	Calculation of Balancing Demand Variance							
16	Allocated actual Balancing Demand cost (Sch. 7, pg. 2, Col A ln 1 * ln 29)	$0	$0	$0	$0	$0	$0	$0
17	Allocated PEPL Balancing Demand & variable cost (Sch. 7, pg. 2, Col A ln 2 * ln 29)	149	10,477	6,985	11,354	6,956	18,496	54,417
18	Total actual Balancing Demand cost incurred (ln 16 + ln 17)	149	10,477	6,985	11,354	6,956	18,496	54,417
19	Actual Balancing Demand Cost Billed including Utility Gross Receipts Tax (Sch. 6A, ln 36)	$258	$18,554	$11,305	$19,513	$9,852	$18,063	$77,545
20	Balancing Demand Cost Variance from Cause No. 37399 - GCA 158 (Sch. 1, pg. 2 Jun., 2023 ln 11)	(17)	(992)	-	-	-	-	(1,009)
21	Balancing Demand Cost Variance from Cause No. 37399 - GCA 158 (Sch. 1, pg. 3 Jun., 2023 ln 27)	-	-	(1,209)	(1,061)	906	4,833	3,469
22	Balancing Demand cost recovered to be reconciled with actual Balancing Demand Cost Incurred (ln 19 - ln 20 - ln 21)	$275	$19,546	$12,514	$20,574	$8,946	$13,230	$75,085
23	Balancing Demand cost variance (over)/underrecovery (ln 18 - ln 22)	($126)	($9,069)	($5,529)	($9,220)	($1,990)	$5,266	($20,668)

Citizens Gas
Calculation of Actual Gas Supply and Balancing Demand Cost Variance
June 2023

Line No.		A Gas Rate No. D1	B Gas Rate No. D2	C Gas Rate No. D3/No. D7	D Gas Rate No. D4	E Gas Rate No. D5	F Gas Rate No. D9	G All GCA Classes
	Calculation of Allocation Factors							
24	Retail gas sales - Dths	4,873	343,593	57,257	207,196	-	-	612,919
25	Standard Delivery - Dths	-	-	159,434	160,733	152,786	27,495	500,448
26	Basic Delivery - Dths	-	-	12,361	4,403	75,319	579,035	671,118
27	Total Throughput - Dths (ln 24 + ln 25 + ln 26)	4,873	343,593	229,052	372,332	228,105	606,530	1,784,485
28	Retail sales allocation factor (ln 24 / ln 24, col. G)	0.007950	0.560585	0.093417	0.338048	0.000000	0.000000	1.000000
29	Throughput subject to Balancing GCA allocation factor (ln 27 / ln 27, column G)	0.002731	0.192544	0.128357	0.208650	0.127827	0.339891	1.000000
	Calculation of Gas Supply Charge Recovery							
30	Gas Supply Charge Cause No. 37399 - GCA 158 (D1 & D2 excludes balancing charges) per Dth	$3.596	$4.771	$2.851	$4.701	$0.000	$0.000	
31	Gas Supply Charge Recovery (ln 24 * ln 30)	$17,523	$1,639,282	$163,240	$974,028	$0	$0	$2,794,073
	Calculation of Balancing Charge Recovery							
32	Balancing GCA Charge Cause No. 37399 - GCA 158 Standard & Retail Customers (per Dth)	$0.053	$0.054	$0.052	$0.053	$0.063	$0.320	
33	Balancing GCA Charge Cause No. 37399 - GCA 158 Basic Delivery Customers (per Dth)	-	-	$0.003	$0.003	$0.003	$0.016	
34	Balancing Charge Recovery - Standard & Retail (ln 24 + ln 25) * (ln 32)	$258	$18,554	$11,268	$19,500	$9,626	$8,798	$68,004
35	Balancing Charge Recovery - Basic (ln 26 * ln 33)	-	-	$37	$13	$226	$9,265	$9,541
36	Total Balancing Charge Recovery (ln 34 + ln 35)	$258	$18,554	$11,305	$19,513	$9,852	$18,063	$77,545

Citizens Gas
Calculation of Actual Gas Supply and Balancing Demand Cost Variance
July 2023

Line No		Gas Rate No. D1	Gas Rate No. D2	Gas Rate No. D3/No. D7	Gas Rate No. D4	Gas Rate No. D5	All GCA Classes
	Calculation of Gas Supply Variance						
1	Retail Peak day demand allocation factor Cause No. 37399 - GCA 140	0.003153	0.740425	0.006293	0.250129	0.000000	1.000000
2	Retail Throughput demand allocation factor Cause No. 37399 - GCA 140	0.003754	0.705611	0.019399	0.271236	0.000000	1.000000
3	Retail Peak day/Retail throughput demand allocation factor (ln 1 * 79%) + (ln 2 * 21%)	0.003279	0.733115	0.009045	0.254561	0.000000	1.000000
4	Normalized Retail Seasonal Demand Allocation Factor Cause No. 37399 - GCA 140	0.003122	0.733268	0.003164	0.260446	0.000000	1.000000
5	Actual net Demand cost allocated (ln 3 * Schedule 7, pg. 1,Col C ln 1)	$2,742	$613,079	$7,564	$212,881	$0	$836,266
6	Allocated other demand costs (ln 2 * ((Schedule 7 pg. 1, Col C ln 4))	(1,944)	(365,369)	(10,045)	(140,448)	0	(517,806)
7	Allocated contracted storage costs (ln 4 * Schedule 7 pg. 1, Col D ln 3))	1,734	407,327	1,758	144,676	0	555,495
8	Actual other non-demand gas costs (Sch. 7 pg. 1, Col D, ln 2 + ln 4) * (Sch. 6B, ln 28))	9,237	741,002	117,204	462,322	0	1,329,765
9	Total actual cost of gas incurred (lns 5+6+7+8)	$11,769	$1,396,039	$116,481	$679,431	$0	$2,203,720
10	Actual cost of gas billed including Utility Gross Receipts Tax (Sch. 6B, ln 31)	$19,662	$2,081,520	$193,296	$1,212,923	$0	$3,507,401
11	Net - Write Off Recovered (Sch 12 C ln 9)	156	32,063	58	4,599	0	36,876
12	Variance from Cause No. 37399-GCA 158 Filing (Sch. 1, pg. 2 Jul., 2023 ln 17)	1,112	66,671	8,766	26,216	0	102,765
13	Refund from cause No. 37399- GCA 158 Filing (Sch. 1, pg. 2 Jul., 2023 ln 18)	0	0	0	0	0	0
14	Gas cost recovered to be reconciled with actual cost of gas incurred (ln 10 - ln 11 - ln 12 + ln 13)	$18,394	$1,982,786	$184,472	$1,182,108	$0	$3,367,760
15	Gas cost variance (over)/underrecovery (ln 9 - ln 14)	($6,625)	($586,747)	($67,991)	($502,677)	$0	($1,164,040)

Citizens Gas
Calculation of Actual Gas Supply and Balancing Demand Cost Variance
July 2023

Line No		Gas Rate No. D1	Gas Rate No. D2	Gas Rate No. D3/No. D7	Gas Rate No. D4	Gas Rate No. D5	Gas Rate No. D9	All GCA Classes
	Calculation of Balancing Demand Variance							
16	Allocated actual Balancing Demand cost ((Sch. 7, pg. 2, Col B ln 1 *) *ln 29)	$0	$0	$0	$0	$0	$0	$0
17	Allocated ADS2 Balancing Demand & variable cost ((Sch. 7, pg. 2, Col B ln 2) * ln 29)	147	11,810	7,233	11,586	6,975	17,188	54,939
18	Total actual Balancing Demand cost incurred (ln16 + ln 17)	$147	$11,810	$7,233	$11,586	$6,975	$17,188	$54,939
19	Actual Balancing Demand Cost Billed including Utility Gross Receipts Tax (Sch. 6B, ln 36)	$253	$20,638	$11,522	$19,668	$9,830	$15,903	$77,814
20	Balancing Demand Cost Variance from Cause No. 37399 - GCA 158 (Sch. 1, pg. 2 Jul., 2023 ln 11)	(13)	(874)	-	-	-	-	(887)
21	Balancing Demand Cost Variance from Cause No. 37399 - GCA 158 (Sch. 1, pg. 3 Jul., 2023 ln 27)	-	-	(1,209)	(1,031)	909	4,814	3,483
22	Balancing Demand cost recovered to be reconciled with actual Balancing Demand Cost Incurred (ln 19 - ln 20 - ln 21)	$266	$21,512	$12,731	$20,699	$8,921	$11,089	$75,218
23	Balancing Demand cost variance (over)/underrecovery (ln 18 - ln 22)	($119)	($9,702)	($5,498)	($9,113)	($1,946)	$6,099	($20,279)

Citizens Gas
Calculation of Actual Gas Supply and Balancing Demand Cost Variance
July 2023

Line No.		A Gas Rate No. D1	B Gas Rate No. D2	C Gas Rate No. D3/No. D7	D Gas Rate No. D4	E Gas Rate No. D5	F Gas Rate No. D9	G All GCA Classes
	Calculation of Allocation Factors							
24	Retail gas sales - Dths	4,594	368,541	58,292	229,938	-	-	661,365
25	Standard Delivery - Dths	-	-	154,356	127,433	148,015	23,926	453,730
26	Basic Delivery - Dths	-	-	13,071	4,169	69,649	512,441	599,330
27	Total Throughput - Dths (ln 24 + ln 25 + ln 26)	4,594	368,541	225,719	361,540	217,664	536,367	1,714,425
28	Retail sales allocation factor (ln 24 / ln 24, col. G)	0.006946	0.557243	0.088139	0.347672	0.000000	0.000000	1.000000
29	Throughput subject to Balancing GCA allocation factor (ln 27 / ln 27, column G)	0.002680	0.214965	0.131659	0.210881	0.126960	0.312855	1.000000
	Calculation of Gas Supply Charge Recovery							
30	Gas Supply Charge Cause No. 37399 - GCA 158 (D1 & D2 excludes balancing charges) per Dth	$4.280	$5.648	$3.316	$5.275	$0.000	$0.000	
31	Gas Supply Charge Recovery (ln 24* ln 30)	$19,662	$2,081,520	$ 193,296	$1,212,923	$0	$0	$3,507,401
	Calculation of Balancing Charge Recovery							
32	Balancing GCA Charge Cause No. 37399 - GCA 158 Standard & Retail Customers (per Dth)	$0.055	$0.056	$0.054	$0.055	$0.065	$0.322	
33	Balancing GCA Charge Cause No. 37399 - GCA 158 Basic Delivery Customers (per Dth)	-	-	$0.003	$0.003	$0.003	$0.016	
34	Balancing Charge Recovery - Standard & Retail (ln 24 + ln 25) * (ln 32)	$253	$20,638	$11,483	$19,655	$9,621	$7,704	$69,354
35	Balancing Charge Recovery - Basic (ln 26 * ln 33)	-	-	$39	$13	$209	$8,199	$8,460
36	Total Balancing Charge Recovery (ln 34 + ln 35)	$253	$20,638	$11,522	$19,668	$9,830	$15,903	$77,814

Citizens Gas
Calculation of Actual Gas Supply and Balancing Demand Cost Variance
August 2023

Line No		Gas Rate No. D1	Gas Rate No. D2	Gas Rate No. D3/No. D7	Gas Rate No. D4	Gas Rate No. D5	All GCA Classes
	Calculation of Gas Supply Variance						
1	Retail Peak day demand allocation factor Cause No. 37399 - GCA 140	0.003153	0.740425	0.006293	0.250129	0.000000	1.000000
2	Retail Throughput demand allocation factor Cause No. 37399 - GCA 140	0.003754	0.705611	0.019399	0.271236	0.000000	1.000000
3	Retail Peak day/Retail throughput demand allocation factor (ln 1 * 79%) + (ln 2 * 21%)	0.003279	0.733115	0.009045	0.254561	0.000000	1.000000
4	Normalized Retail Seasonal Demand Allocation Factor Cause No. 37399 - GCA 140	0.003122	0.733268	0.003164	0.260446	0.000000	1.000000
5	Actual net Demand cost allocated (ln 3 * Schedule 7 pg. 1, Col E ln 1)	$2,948	$659,037	$8,131	$228,839	$0	$898,955
6	Allocated other demand costs (ln 2 * (Schedule 7 pg. 1, Col E, ln 4))	(2,407)	(452,503)	(12,440)	(173,941)	0	(641,291)
7	Allocated contracted storage costs (ln 4 * Schedule 7 pg. 1,Col F ln 3)	1,682	394,949	1,704	140,280	0	538,615
8	Actual other non-demand gas costs ((Sch. 7 pg. 1, ln 2 + ln 4) * (Sch. 6C, ln 28))	6,364	544,986	102,780	356,449	0	1,010,579
9	Total actual cost of gas incurred (ln 5 + ln 6 + ln 7 + ln 8)	$8,587	$1,146,469	$100,175	$551,627	$0	$1,806,858
10	Actual cost of gas billed including Utility Gross Receipts Tax (Sch. 6C, ln 31)	$16,715	$1,894,313	$208,444	$1,157,364	$0	$3,276,836
11	Actual cost of gas billed excluding Net - Write Off Recovered (Sch 12 C ln 15)	132	29,059	64	4,248	0	33,503
12	Variance from Cause No. 37399-GCA 158 Filing (Sch. 1, pg. 2 Aug., 2023, ln 17)	$1,112	$66,330	$8,718	$26,029	$0	102,189
13	Refund from cause No. 37399- GCA 158 Filing (Sch. 1, pg. 2 Aug., 2023, ln 18)	0	0	0	0	0	0
14	Gas cost recovered to be reconciled with actual cost of gas incurred (ln 10 - ln 11 - ln 12 + ln 13)	$15,471	$1,798,924	$199,662	$1,127,087	$0	$3,141,144
15	Gas cost variance (over)/underrecovery (ln 9 - ln 14)	($6,884)	($652,455)	($99,487)	($575,460)	$0	($1,334,286)

Citizens Gas
Calculation of Actual Gas Supply and Balancing Demand Cost Variance
August 2023

Line No		Gas Rate No. D1	Gas Rate No. D2	Gas Rate No. D3/No. D7	Gas Rate No. D4	Gas Rate No. D5	Gas Rate No. D9	All GCA Classes
	Calculation of Balancing Demand Variance							
16	Allocated actual Balancing Demand cost (Sch. 7, pg. 2, ln 1 * ln 29)	$0	$0	$0	$0	$0	$0	$0
17	Allocated ADS2 Balancing Demand cost (Sch. 7, pg. 2, ln 2 * ln 29)	$124	$10,651	$7,665	$12,191	$7,612	$15,027	$53,270
18	Total actual Balancing Demand cost incurred (ln 16 + ln 17)	$124	$10,651	$7,665	$12,191	$7,612	$15,027	$53,270
19	Actual Balancing Demand Cost Billed including Utility Gross Receipts Tax (ln 36)	$216	$18,803	$12,344	$20,911	$11,184	$14,082	$77,540
20	Balancing Demand Cost Variance from Cause No. 37399 - GCA 158 (Sch. 1, pg. 2 Aug., 2023 ln 11)	(13)	(870)	-	-	-	-	(883)
21	Balancing Demand Cost Variance from Cause No. 37399 - GCA 158 (Sch. 1, pg. 3 Aug., 2023 ln 27)	-	-	(1,207)	(1,031)	912	4,814	3,488
22	Balancing Demand cost recovered to be reconciled with actual Balancing Demand Cost Incurred (ln19 - ln20 - ln21)	$229	$19,673	$13,551	$21,942	$10,272	$9,268	$74,935
23	Balancing Demand cost variance (over)/underrecovery (ln 18 - ln 22)	($105)	($9,022)	($5,886)	($9,751)	($2,660)	$5,759	($21,665)

Citizens Gas
Calculation of Actual Gas Supply and Balancing Demand Cost Variance
August 2023

Line No.		A Gas Rate No. D1	B Gas Rate No. D2	C Gas Rate No. D3/No. D7	D Gas Rate No. D4	E Gas Rate No. D5	F Gas Rate No. D9	G All GCA Classes
	Calculation of Allocation Factors							
24	Retail gas sales - Dth	3,992	341,872	64,474	223,602	-	-	633,940
25	Standard Delivery - Dths	-	-	167,630	163,406	171,332	20,865	523,233
26	Basic Delivery - Dths	-	-	13,921	4,295	72,982	461,486	552,684
27	Total Throughput - Dths (ln 24 + ln 25 + ln 26)	3,992	341,872	246,025	391,303	244,314	482,351	1,709,857
28	Retail sales allocation factor (ln 24 / ln 24, col. G)	0.006297	0.539281	0.101704	0.352718	0.000000	0.000000	1.000000
29	Throughput subject to Balancing GCA allocation factor (ln 27 / 27, column G)	0.002335	0.199942	0.143886	0.228851	0.142886	0.282100	1.000000
	Calculation of Gas Supply Charge Recovery							
30	Gas Supply Charge Cause No. 37399 - GCA 158 (D1 & D2 excludes balancing charges) per Dth	$4.187	$5.541	$3.233	$5.176	$0.000	$0.000	
31	Gas Supply Charge Recovery (ln 24 * ln 30)	$16,715	$1,894,313	$208,444	$1,157,364	$0	$0	$3,276,836
	Calculation of Balancing Charge Recovery							
32	Balancing GCA Charge Cause No. 37399 - GCA 158 Standard & Retail Customers (per Dth)	$0.054	$0.055	$0.053	$0.054	$0.064	$0.321	
33	Balancing GCA Charge Cause No. 37399 - GCA 158 Basic Delivery Customers (per Dth)	-	-	$0.003	$0.003	$0.003	$0.016	
34	Balancing Charge Recovery - Standard & Retail (ln 24 + ln 25) * (ln 32)	$216	$18,803	$12,302	$20,898	$10,965	$6,698	$69,882
35	Balancing Charge Recovery - Basic (ln 26 * ln 33)	-	-	$42	$13	$219	$7,384	$7,658
36	Total Balancing Charge Recovery (ln 34 + ln 35)	$216	$18,803	$12,344	$20,911	$11,184	$14,082	$77,540

Citizens Gas
Trailing Twelve Month Variance
For July 2022 through August 2023

Line No.			A July 2022	B August 2022	C September 2022	D October 2022	E November 2022	F December 2022	G January 2023	H February 2023	I March 2023	J April 2023	K May 2023	L June 2023	M July 2023	N August 2023
1	Actual Cost of Gas	Total Sch 6 pg 1 ln 9 + Sch 6 pg 2 ln 18	$2,056,117	$5,229,040	$4,610,291	$7,777,595	$18,680,683	$29,738,958	$22,962,231	$14,239,239	$18,188,740	$6,818,989	$3,567,574	$1,944,899	$2,258,659	$1,860,128
2	Variance	Total Sch 6 pg 1 ln 15 + Sch 6 pg 2 ln 23	($51,161)	$2,170,973	$2,832,132	$765,600	($75,147)	$4,873,740	($2,605,168)	($3,824,137)	$2,292,009	($147,215)	($409,497)	($784,320)	($1,184,319)	($1,355,951)
3										Gas Cost Trailing Twelve Months (ln 1, col A-L)				$135,814,356		
4										Variance Trailing Twelve Months (ln 2, col A-L)				$5,037,809		
5										Total Trailing Twelve Months % Variance (ln 4 / ln 3)				3.71%		
6										Gas Cost Trailing Twelve Months (ln 1, col B-M)					$136,016,898	
7										Variance Trailing Twelve Months (ln 2, col B-M)					$3,904,651	
8										Total Trailing Twelve Months % Variance (ln 7 / ln 6)					2.87%	
9										Gas Cost Trailing Twelve Months (ln 1, col C-N)						$132,647,986
10										Variance Trailing Twelve Months (ln 2, col C-N)						$377,727
11										Total Trailing Twelve Months % Variance (ln 10 / ln 9)						0.28%

Citizens Gas
Determination of Actual Retail Gas Costs
For Three Months Ending August 31, 2023

		A	B	C	D	E	F
		June 2023		July 2023		August 2023	
Line No.		Demand	Non-Demand	Demand	Non-Demand	Demand	Non-Demand
1	Demand gas costs (Sch. 8)	$745,273	-	$836,266	-	$898,955	-
2	Pipeline non-demand gas costs (Schedule 8)	-	3,323,819	-	3,261,857	-	3,444,151
3	PEPL Contracted storage and related transportation costs (Sch. 9)	-	550,212	-	555,495	-	538,615
4	Net cost of gas (injected into) withdrawn from storage (Schedule 10)	(513,011)	(2,215,811)	(517,806)	(1,932,092)	(641,291)	(2,433,572)
5	Total gas costs	$232,262	$1,658,220	$318,460	$1,885,260	$257,664	$1,549,194

Citizens Gas
Determination of Actual Balancing Costs
For Three Months Ending August 31, 2023

Line No.		A June 2023	B July 2023	C August 2023
1	Balancing Demand Costs (Schedule 8)	$0	$0	$0
2	PEPL Balancing Demand Costs (Sch. 9)	54,417	54,939	53,270
3	Total Balancing Costs	$54,417	$54,939	$53,270

Citizens Gas
Purchased Gas Cost - Per Books
June 2023

Line No.		A	B	C	D	E	F	G	H	I
		Demand - Dth	Commodity Dth	Demand $/Unit	Commodity $/Dth	Other $/Unit	Demand (A x C)	Commodity (B x D)	Other	Total (F + G + H)
	Accrual - May, 2023									
	Exelon Generation Company									
1	Panhandle Eastern Pipeline - TOR	31,643	546,499	$ 12.3764	$ 1.8888		$ 391,628	$ 1,032,200		$ 1,423,828
2	MGT Pipeline	930,000	-	0.0790	-		73,455	2,044		75,499
3	Indiana Municipal Gas Purchasing Authority - TOR		-	-	-			-		-
4	Indiana Municipal Gas Purchasing Authority - Prepay	-	-	-	-		-	-		-
5	Texas Gas Transmission - Nominated Demand	974,113		0.3543	-		345,128			345,128
6	Texas Gas Transmission - Unnominated Demand	-		-	-		-			-
7	Texas Gas Transmission - Commodity - TOR		308,760	-	1.9030			587,576		587,576
8	Texas Gas Transmission - Unnominated Injection	(382,096)	(382,096)	0.3549	2.5936		(135,606)	(991,004)		(1,126,610)
9	Texas Gas Transmission - Unnominated Withdrawal	10,869	10,869	0.3549	2.5936		3,857	28,190		32,047
10	Texas Gas Transmission - Unomminated Seasonal GasStorage Refill			-	-		-	-		-
11	Rockies Express - Delivered Supply - (BP PEAK B)		309,721	-	1.9112		-	591,945		591,945
12	Rockies Express - Delivered Supply - (BP PEAK A)		310,000	-	1.7820		-	552,420		552,420
13	Rockies Express - EAST	20,000	619,442	16.7292	1.7273		334,583	1,069,969		1,404,552
14	Intraday Purchases		271,300	-	2.0133			546,208		546,208
15	Fuel Retention Volumes		-	-	-					-
16	TGT,PEPL, & MGT and REX Swing/Daily Gas (Commodity)		224,247	-	1.9451			436,177		436,177
17	TGT,PEPL, & MGT and REX Swing/Daily Gas (Demand)			-	-					-
18	Hedging Transaction Cost			-	-			1,939,880		1,939,880
19	Imbalance		1,772	-	2.5942			4,597		4,597
20	Utilization Fee			-	-		(203,570)	-		(203,570)
21	Net Demand Cost Charges - AMA			-	-		-			-
22	Wholesale Sales	-	(125,000)	-	1.7866		-	(223,323)		(223,323)
23	Third Party Supplier Balancing Gas Costs		139,979	-				243,573		243,573
24	Boil-off / Peaking purchase		47,262	-	2.1170			100,054		100,054
25	MGT Cash Out Imbalance		-	-	-			-		-
26	NSS Injection fuel loss	-	(712)	-	-		-			-
27	Exelon Cash Out Imbalance		-		-			-		-
28	Subtotal		2,282,043				$809,475	$5,920,506	$0	$6,729,981
	Actual - May, 2023									
	Exelon Generation Company									
29	Panhandle Eastern Pipeline - TOR	31,643	546,499	$ 12.3396	$ 1.8888		$ 390,461	$ 1,032,200		$ 1,422,661
30	MGT Pipeline	930,000	-	0.0790	-		73,455	2,044		75,499
31	Indiana Municipal Gas Purchasing Authority - TOR		-	-	-			-		-
32	Indiana Municipal Gas Purchasing Authority - Prepay	-	-	-	-		-	-		-
33	Texas Gas Transmission - Nominated Demand	974,113		0.3543	-		345,128			345,128
34	Texas Gas Transmission - Unnominated Demand	-		-	-		-			-
35	Texas Gas Transmission - Commodity - TOR		308,760	-	1.9030			587,576		587,576
36	Texas Gas Transmission - Unnominated Injection	(382,096)	(382,096)	0.3554	2.5964		(135,797)	(992,074)		(1,127,871)
37	Texas Gas Transmission - Unnominated Withdrawal	10,869	10,869	0.3554	2.5964		3,863	28,220		32,083
38	Texas Gas Transmission - Unomminated Seasonal GasStorage Refill			-	-		-	-		-
39	Rockies Express - Delivered Supply - (BP PEAK B)		309,721	-	1.9112		-	591,945		591,945
40	Rockies Express - Delivered Supply - (BP PEAK A)		310,000	-	1.7820		-	552,420		552,420
41	Rockies Express - EAST	20,000	619,442	16.7292	1.7273		334,583	1,069,969		1,404,552
42	Intraday Purchases		271,300	-	2.0133			546,208		546,208
43	Fuel Retention Volumes		-	-	-					-
44	TGT,PEPL, & MGT and REX Swing/Daily Gas (Commodity)		224,247	-	1.9451			436,177		436,177
45	TGT,PEPL, & MGT and REX Swing/Daily Gas (Demand)			-	-					-
46	Hedging Transaction Cost			-	-			1,939,880		1,939,880
47	Imbalance		1,772	-	2.5971			4,602		4,602
48	Utilization Fee			-	-		(203,570)	-		(203,570)
49	Net Demand Cost Charges - AMA			-	-		-			-
50	Wholesale Sales	-	(125,000)	-	1.7866		-	(223,323)		(223,323)
51	Third Party Supplier Balancing Gas Costs		139,979	-				243,573		243,573
52	Boil-off / Peaking purchase		47,262	-	2.1170			100,054		100,054
53	MGT Cash Out Imbalance		(7,424)	-	1.6067			(11,928)		(11,928)
54	NSS Injection fuel loss	-	(712)							-
55	Exelon Cash Out Imbalance		-	-	-		-	-		-
56	Subtotal		2,274,619				$808,123	$5,907,543	$0	$6,715,666

Citizens Gas
Purchased Gas Cost - Per Books
June 2023

		A	B	C	D	E	F	G	H	I
		Demand - Dth	Commodity Dth	Demand $/Unit	Commodity $/Dth	Other $/Unit	Demand (A x C)	Commodity (B x D)	Other	Total (F + G + H)
	Accrual - June, 2023									
	Exelon Generation Company									
57	Panhandle Eastern Pipeline - TOR	31,643	546,510	$ 12.2986	$ 1.9294		$ 389,164	$ 1,054,442		$ 1,443,606
58	MGT Gas Pipeline -	900,000	-	0.0816	-		73,455	1,978		75,433
59	Indiana Municipal Gas Purchasing Authority - TOR		-	-	-			-		-
60	Indiana Municipal Gas Purchasing Authority - Prepay	-	-	-	-		-	-		-
61	Texas Gas Transmission - Nominated Demand	942,690		0.3543	-		333,995			333,995
62	Texas Gas Transmission - Unnominated Demand	-	-	-	-		-			-
63	Texas Gas Transmission - Commodity - TOR		308,760	-	1.9388			598,631		598,631
64	Texas Gas Transmission - Unnominated Injection	(505,946)	(505,946)	0.4053	2.2703		(205,060)	(1,148,649)		(1,353,709)
65	Texas Gas Transmission - Unnominated Withdrawal	143	143	0.4056	2.2727		58	325		383
66	Texas Gas Transmission - Unomminated Seasonal GasStorage Refill			-	-		24,000	(736,000)		(712,000)
67	Rockies Express - Delivered Supply - (BP PEAK B)		299,730	-	1.9753			592,050		592,050
68	Rockies Express - Delivered Supply - (BP PEAK A)		300,000	-	1.8460			553,800		553,800
69	Rockies Express - EAST	20,000	599,460	16.7292	1.3630		334,583	817,091		1,151,674
70	Intraday Purchases		103,200	-	1.8423			190,125		190,125
71	Fuel Retention Volumes		-	-	-					-
72	TGT,PEPL, & MGT and REX Swing/Daily Gas (Commodity)		148,322	-	1.9396			287,692		287,692
73	TGT,PEPL, & MGT and REX Swing/Daily Gas (Demand)			-	-					-
74	Hedging Transaction Cost			-	-			1,148,859		1,148,859
75	Imbalance		13,128	-	1.8591			24,406		24,406
76	Utilization Fee			-	-		(203,570)	-		(203,570)
77	Net Demand Cost Charges - AMA			-	-		-			-
78	Wholesale Sales		(171,465)	-	2.0725		-	(355,358)		(355,358)
79	Third Party Supplier Balancing Gas Costs		93,787	-				175,014		175,014
80	Boil-off / Peaking purchase		60,695	-	2.1810			132,376		132,376
81	MGT Cash Out Imbalance		-	-	-			-		-
82	NSS Injection fuel loss		(1,525)	-	-		-			-
83	Exelon Cash Out Imbalance		-		-			-		-
84	Subtotal		1,794,799				$ 746,625	$ 3,336,782	$ -	$ 4,083,407
85	Total Purchased Costs (line 84 + line 56 - line 28)		1,787,375				$ 745,273	$ 3,323,819	$ -	$ 4,069,092
86	Total TGT Unnominated Demand Cost (line 62 + line 34 - line 6)						$ -			
87	Total Purchase Cost excluding TGT Demand Unnom. (ln 85 - ln 86)		1,787,375				$ 745,273			
88	TGT Unnominated Demand Cost - Retail (line 86 * 90%)						$ -			
89	Balancing Demand Cost (line 86 * 10%)						$ -			

Citizens Gas

Purchased Gas Cost - Per Books

July 2023

Line No.		A Demand - Dth	B Commodity Dth	C Demand $/Unit	D Commodity $/Dth	E Other $/Unit	F Demand (A x C)	G Commodity (B x D)	H Other	I Total (F + G + H)
	Accrual - June, 2023									
	Exelon Generation Company									
1	Panhandle Eastern Pipeline - TOR	31,643	546,510	$ 12.2986	$ 1.9294		$ 389,164	$ 1,054,442		$ 1,443,606
2	MGT Gas Pipeline -	900,000	-	0.0816	-		73,455	1,978		75,433
3	Indiana Municipal Gas Purchasing Authority - TOR		-	-	-			-		-
4	Indiana Municipal Gas Purchasing Authority - Prepay	-	-	-	-		-	-		-
5	Texas Gas Transmission - Nominated Demand	942,690		0.3543	-		333,995			333,995
6	Texas Gas Transmission - Unnominated Demand	-	-	-	-		-			-
7	Texas Gas Transmission - Commodity - TOR		308,760	-	1.9388			598,631		598,631
8	Texas Gas Transmission - Unnominated Injection	(505,946)	(505,946)	0.4053	2.2703		(205,060)	(1,148,649)		(1,353,709)
9	Texas Gas Transmission - Unnominated Withdrawal	143	143	0.4056	2.2727		58	325		383
10	Texas Gas Transmission - Unomminated Seasonal GasStorage Refill	0		-	-		24,000	(736,000)		(712,000)
11	Rockies Express - Delivered Supply - (BP PEAK B)		299,730	-	1.9753			592,050		592,050
12	Rockies Express - Delivered Supply - (BP PEAK A)		300,000	-	1.8460			553,800		553,800
13	Rockies Express - EAST	20,000	599,460	16.7292	1.3630		334,583	817,091		1,151,674
14	Intraday Purchases		103,200	-	1.8423			190,125		190,125
15	Fuel Retention Volumes		-	-	-					-
16	TGT,PEPL, & MGT and REX Swing/Daily Gas (Commodity)		148,322	-	1.9396			287,692		287,692
17	TGT,PEPL, & MGT and REX Swing/Daily Gas (Demand)			-	-					-
18	Hedging Transaction Cost			-	-			1,148,859		1,148,859
19	Imbalance		13,128	-	1.8591			24,406		24,406
20	Utilization Fee			-	-		(203,570)	-		(203,570)
21	Net Demand Cost Charges - AMA			-	-		-			-
22	Wholesale Sales	-	(171,465)	-	2.0725		-	(355,358)		(355,358)
23	Third Party Supplier Balancing Gas Costs		93,787	-				175,014		175,014
24	Boil-off / Peaking purchase		60,695	-	2.1810			132,376		132,376
25	MGT Cash Out Imbalance		-	-	-			-		-
26	NSS Injection fuel loss		(1,525)	-	-		-	-		-
27	Exelon Cash Out Imbalance		-		-			-		-
28	Subtotal		1,794,799				$ 746,625	$ 3,336,782	$ -	$ 4,083,407
	Actual - June, 2023									
29	Panhandle Eastern Pipeline - TOR	31,643	546,510	$ 12.2878	1.9294		$ 388,823	$ 1,054,442		$ 1,443,265
30	MGT Gas Pipeline -	900,000	-	0.0816	-		73,455	1,978		75,433
31	Indiana Municipal Gas Purchasing Authority - TOR		-	-	-			-		-
32	Indiana Municipal Gas Purchasing Authority - Prepay	-	-	-	-		-	-		-
33	Texas Gas Transmission - Nominated Demand	942,690	-	0.3543	-		333,995			333,995
34	Texas Gas Transmission - Unnominated Demand	-	-	-	-		-			-
35	Texas Gas Transmission - Commodity - TOR		308,760	-	1.9388		-	598,631		598,631
36	Texas Gas Transmission - Unnominated Injection	(505,946)	(505,946)	0.4054	2.2713		(205,111)	(1,149,155)		(1,354,266)
37	Texas Gas Transmission - Unnominated Withdrawal	143	143	0.4056	2.2727		58	325		383
38	Texas Gas Transmission - Unomminated Seasonal GasStorage Refill			-	-		24,000	(736,000)		(712,000)
39	Rockies Express - Delivered Supply - (BP PEAK B)		299,730	-	1.9753			592,050		592,050
40	Rockies Express - Delivered Supply - (BP PEAK A)		300,000	-	1.8460			553,800		553,800
41	Rockies Express - EAST	20,000	599,460	16.7292	1.3630		334,583	817,091		1,151,674
42	Intraday Purchases		103,200	-	1.8423		-	190,125		190,125
43	Fuel Retention Volumes		-	-	-					-
44	TGT,PEPL, & MGT and REX Swing/Daily Gas (Commodity)		148,322	-	1.9396			287,692		287,692
45	TGT,PEPL, & MGT and REX Swing/Daily Gas (Demand)		-	-	-					-
46	Hedging Transaction Cost			-	-			1,148,859		1,148,859
47	Imbalance		13,128	-	1.8589			24,404		24,404
48	Utilization Fee		-	-	-		(203,570)	-		(203,570)
49	Net Demand Cost Charges - AMA			-	-		-	-		-
50	Wholesale Sales	-	(171,465)	-	2.0725		-	(355,358)		(355,358)
51	Third Party Supplier Balancing Gas Costs		93,787	-			-	175,014		175,014
52	Boil-off / Peaking purchase		60,695	-	2.1810		-	132,376		132,376
53	MGT Cash Out Imbalance		(1,636)	-	0.8667		-	(1,418)		(1,418)
54	NSS Injection fuel loss		(1,525)	-	-					-
55	Exelon Cash Out Imbalance		-		-			-		-
56	Subtotal		1,793,163				$ 746,233	$ 3,334,856	$0	$ 4,081,089

Citizens Gas

Purchased Gas Cost - Per Books

July 2023

		A	B	C	D	E	F	G	H	I
		Demand - Dth	Commodity Dth	Demand $/Unit	Commodity $/Dth	Other $/Unit	Demand (A x C)	Commodity (B x D)	Other	Total (F + G + H)
	Accrual - July, 2023									
	Exelon Generation Company									
57	Panhandle Eastern Pipeline - TOR	31,643	546,499	$ 12.3764	$ 2.3265		$ 391,628	$ 1,271,433		$ 1,663,061
58	MGT Pipeline	930,000	-	0.0790	-		73,455	2,044		75,499
59	Indiana Municipal Gas Purchasing Authority - TOR		-	-	-			-		-
60	Indiana Municipal Gas Purchasing Authority - Prepay	-	-	-	-		-	-		-
61	Texas Gas Transmission - Nominated Demand	974,113		0.3543	-		345,128			345,128
62	Texas Gas Transmission - Unnominated Demand	-	-	-	-		-			-
63	Texas Gas Transmission - Commodity - TOR	-	308,760	-	2.3543			726,917		726,917
64	Texas Gas Transmission - Unnominated Injection	(309,771)	(309,771)	0.5178	2.6543		(160,399)	(822,225)		(982,624)
65	Texas Gas Transmission - Unnominated Withdrawal	5,472	5,472	0.5177	2.6542		2,833	14,524		17,357
66	Texas Gas Transmission - Unomminated Seasonal GasStorage Refill			-	-		53,000	(659,000)		(606,000)
67	Rockies Express - Delivered Supply - (BP PEAK B)	-	309,721	-	2.3977		-	742,605		742,605
68	Rockies Express - Delivered Supply - (BP PEAK)		310,000	-	2.2680			703,080		703,080
69	Rockies Express - EAST	20,000	71,486	16.7292	1.4000		334,583	100,081		434,664
70	Intraday Purchases		66,000	-	2.3092			152,405		152,405
71	Fuel Retention Volumes		-	-	-					-
72	TGT,PEPL, & MGT and REX Swing/Daily Gas (Commodity)		552,246	-	1.6657			919,893		919,893
73	TGT,PEPL, & MGT and REX Swing/Daily Gas (Demand)			-	-					-
74	Hedging Transaction Cost			-	-			989,134		989,134
75	Imbalance		(2,558)	-	2.2123			(5,659)		(5,659)
76	Utilization Fee			-	-		(203,570)			(203,570)
77	Net Demand Cost Charges - AMA			-	-		-			-
78	Wholesale Sales	-	(509,558)	-	2.2539		-	(1,148,508)		(1,148,508)
79	Third Party Supplier Balancing Gas Costs		81,130	-				133,384		133,384
80	Boil-off / Peaking purchase		55,196	-	2.6030			143,675		143,675
81	MGT Cash Out Imbalance		-	-	-			-		-
82	NSS Injection fuel loss		(705)							-
83	Exelon Cash Out Imbalance		-		-			-		-
84	Subtotal		1,483,918				$ 836,658	$ 3,263,783	$0	$4,100,441
85	Total Purchased Costs (line 84 + line 56 - line 28.)		1,482,282				$836,266	$3,261,857	$0	$4,098,123
86	Total TGT Unnominated Demand Cost (line 62 + line 34 - line 6)						0			
87	Total Purchase Cost excluding TGT Demand Unnom. (ln 85 - ln 86)		1,482,282				$836,266			
88	TGT Unnominated Demand Cost - Retail (line 86 * 90%)						$0			
89	Balancing Demand Cost (line 86 * 10%)						$0			

Citizens Gas
Purchased Gas Cost - Per Books
August 2023

Line No.		A Demand - Dth	B Commodity Dth	C Demand $/Unit	D Commodity $/Dth	E Other $/Unit	F Demand (A x C)	G Commodity (B x D)	H Other	I Total (F + G + H)
	Accrual - July, 2023									
	Exelon Generation Company									
1	Panhandle Eastern Pipeline - TOR	31,643	546,499	$ 12.3764	$ 2.3265		$ 391,628	$ 1,271,433		$ 1,663,061
2	MGT Pipeline	930,000	-	0.0790	-		73,455	2,044		75,499
3	Indiana Municipal Gas Purchasing Authority - TOR	-	-	-	-		-	-		-
4	Indiana Municipal Gas Purchasing Authority - Prepay	-	-	-	-		-	-		-
5	Texas Gas Transmission - Nominated Demand	974,113	-	0.3543	-		345,128	-		345,128
6	Texas Gas Transmission - Unnominated Demand	-	-	-	-		-	-		-
7	Texas Gas Transmission - Commodity - TOR		308,760	-	2.3543			726,917		726,917
8	Texas Gas Transmission - Unnominated Injection	(309,771)	(309,771)	0.5178	2.6543		(160,399)	(822,225)		(982,624)
9	Texas Gas Transmission - Unnominated Withdrawal	5,472	5,472	0.5177	2.6542		2,833	14,524		17,357
10	Texas Gas Transmission - Unomminated Seasonal GasStorage Refill		-	-	-		53,000	(659,000)		(606,000)
11	Rockies Express - Delivered Supply - (BP PEAK B)	-	309,721	-	2.3977		-	742,605		742,605
12	Rockies Express - Delivered Supply - (BP PEAK)	-	310,000	-	2.2680		-	703,080		703,080
13	Rockies Express - EAST	20,000	71,486	16.7292	1.4000		334,583	100,081		434,664
14	Intraday Purchases		66,000	-	2.3092			152,405		152,405
15	Fuel Retention Volumes		-	-	-		-	-		-
16	TGT,PEPL, & MGT and REX Swing/Daily Gas (Commodity)		552,246	-	1.6657		-	919,893		919,893
17	TGT,PEPL, & MGT and REX Swing/Daily Gas (Demand)		-	-	-		-	-		-
18	Hedging Transaction Cost			-	-		-	989,134		989,134
19	Imbalance		(2,558)	-	2.2123			(5,659)		(5,659)
20	Utilization Fee		-	-	-		(203,570)	-		(203,570)
21	Net Demand Cost Charges - AMA		-	-	-		-			-
22	Wholesale Sales	-	(509,558)	-	2.2539		-	(1,148,508)		(1,148,508)
23	Third Party Supplier Balancing Gas Costs		81,130	-				133,384		133,384
24	Boil-off / Peaking purchase		55,196	-	2.6030		-	143,675		143,675
25	MGT Cash Out Imbalance		-	-	-		-	-		-
26	NSS Injection fuel loss		(705)							
27	Exelon Cash Out Imbalance		-		-		-	-		-
28	Sub-total		1,483,918				$836,658	$3,263,783	$0	$4,100,441
	Actual - July, 2023									
	Exelon Generation Company									
29	Panhandle Eastern Pipeline - TOR	31,643	546,499	$ 12.3635	$ 2.3265		391,219	$ 1,271,433		$ 1,662,652
30	MGT Pipeline	930,000	-	0.0790	-		73,455	2,044		75,499
31	Indiana Municipal Gas Purchasing Authority - TOR		-	-	-			-		-
32	Indiana Municipal Gas Purchasing Authority - Prepay	-	-	-	-		-	-		-
33	Texas Gas Transmission - Nominated Demand	974,113	-	0.3543	-		345,128	-		345,128
34	Texas Gas Transmission - Unnominated Demand	-	-	-	-		-	-		-
35	Texas Gas Transmission - Commodity - TOR		308,760	-	2.3543			726,917		726,917
36	Texas Gas Transmission - Unnominated Injection	(309,771)	(309,771)	0.5250	2.6457		(162,630)	(819,561)		(982,191)
37	Texas Gas Transmission - Unnominated Withdrawal	5,472	5,472	0.5250	2.6457		2,873	14,477		17,350
38	Texas Gas Transmission - Unomminated Seasonal GasStorage Refill			-	-		53,000	(659,000)		(606,000)
39	Rockies Express - Delivered Supply - (BP PEAK B)	-	309,721	-	2.3977		-	742,605		742,605
40	Rockies Express - Delivered Supply - (BP PEAK)	-	310,000	-	2.2680			703,080		703,080
41	Rockies Express - EAST	20,000	71,486	16.6988	1.4000		333,976	100,081		434,057
42	Intraday Purchases		66,000	-	2.3092			$152,405		152,405
43	Fuel Retention Volumes		-	-	-					-
44	TGT,PEPL, & MGT and REX Swing/Daily Gas (Commodity)		552,246	-	1.6657			919,893		919,893
45	TGT,PEPL, & MGT and REX Swing/Daily Gas (Demand)			-	-					-
46	Hedging Transaction Cost			-	-			989,134		989,134
47	Imbalance		(2,558)	-	2.2048			(5,640)		(5,640)
48	Utilization Fee			-	-		(203,570)			(203,570)
49	Net Demand Cost Charges - AMA			-	-		-			-
50	Wholesale Sales	-	(509,558)	-	2.2539		-	(1,148,508)		(1,148,508)
51	Third Party Supplier Balancing Gas Costs		81,130	-				133,384		133,384
52	Boil-off / Peaking purchase		55,196	-	2.6030			143,675		143,675
53	MGT Cash Out Imbalance		(608)	-	(3.3816)			2,056		2,056
54	NSS Injection fuel loss		(705)							
55	Exelon Cash Out Imbalance		-		-			-		-
56	Sub-total		1,483,310				$ 833,451	$ 3,268,475	$ -	$ 4,101,926

Citizens Gas
Purchased Gas Cost - Per Books
August 2023

Line No.		A Demand - Dth	B Commodity Dth	C Demand $/Unit	D Commodity $/Dth	E Other $/Unit	F Demand (A x C)	G Commodity (B x D)	H Other	I Total (F + G + H)
	Accrual - August, 2023									
	Exelon Generation Company									
57	Panhandle Eastern Pipeline - TOR	31,643	546,499	$ 12.3764	$ 2.1229		$ 391,628	$ 1,160,162		$ 1,551,790
58	MGT Pipeline	930,000	-	0.0790	-		73,455	2,044		75,499
59	Indiana Municipal Gas Purchasing Authority - TOR		-	-	-			-		-
60	Indiana Municipal Gas Purchasing Authority - Prepay	-	-	-	-		-	-		-
61	Texas Gas Transmission - Nominated Demand	974,113	-	0.3543	-		345,128	-		345,128
62	Texas Gas Transmission - Unnominated Demand	-		-	-		-			-
63	Texas Gas Transmission - Commodity - TOR		308,760	-	2.1544			665,202		665,202
64	Texas Gas Transmission - Unnominated Injection	(184,453)	(184,453)	0.4983	2.5600		(91,913)	(472,200)		(564,113)
65	Texas Gas Transmission - Unnominated Withdrawal	6,143	6,143	0.4983	2.5600		3,061	15,726		18,787
66	Texas Gas Transmission - Unomminated Seasonal GasStorage Refill			-	-		49,790	(687,195)		(637,405)
67	Rockies Express - Delivered Supply - (BP PEAK B)		309,721	-	2.2866		-	708,195		708,195
68	Rockies Express - Delivered Supply - (BP PEAK A)		310,000	-	2.1570		-	668,670		668,670
69	Rockies Express - EAST	20,000	154,845	16.7292	1.2619		334,583	195,394		529,977
70	Intraday Purchases		(162,910)	-	1.1999			(195,479)		(195,479)
71	Fuel Retention Volumes		-	-	-					-
72	TGT,PEPL, & MGT and REX Swing/Daily Gas (Commodity)		449,638	-	1.4022			630,472		630,472
73	TGT,PEPL, & MGT and REX Swing/Daily Gas (Demand)			-	-					-
74	Hedging Transaction Cost			-	-			1,268,858		1,268,858
75	Imbalance		(10,406)	-	2.1586			(22,462)		(22,462)
76	Utilization Fee			-	-		(203,570)			(203,570)
77	Net Demand Cost Charges - AMA			-	-		-			-
78	Wholesale Sales	- .	(277,700)	-	2.2705		-	($630,530)		(630,530)
79	Third Party Supplier Balancing Gas Costs		24,150	-				13,143		13,143
80	Boil-off / Peaking purchase		47,937	-	2.4920			119,459		119,459
81	MGT Cash Out Imbalance		-	-	-			-		-
82	NSS Injection fuel loss		(236)							-
83	Exelon Cash Out Imbalance		-		-			-		-
84	Sub-total		1,521,988				902,162	3,439,459	$ -	4,341,621
85	Total Purchased Costs (line 56 + line 84 - line 28)		1,521,380				$898,955	$3,444,151	$0	$4,343,106
86	Total TGT Unnominated Demand Cost (line 62+ line 34 - line 6)						-			
87	Total Purchase Cost excluding TGT Demand Unnom. (ln 85 - ln 86)		1,521,380				$898,955			
88	TGT Unnominated Demand Cost - Retail (line 86 * 90%)						$0			
89	Balancing Demand Cost (line 86 * 10%)						$0			

Citizens Gas
Actual Information
For Three Months Ending August 31, 2023

Line No.	A	B	C	D	E
	June 2023	Volumes in Dths	Commodity Cost per Dth	% of Total	Reference
1	Intraday Purchases	103,200	$ 1.8423	4.36%	Sch8A, lns 14, 42, 70
2	Index Purchases / Spot	2,054,460	$ 1.7610	86.80%	Sch8A, lns 1,2,3,4,7,11,12,13,29,30,31,32,35,39,40,41,57,58,59,60,63,67,68,69
3	Swing Gas	148,322	$ 1.9396	6.27%	Sch8A, lns 16, 44, 72
4	Boil off/Peaking Purchases	60,695	$ 2.1810	2.56%	Sch8A, lns 24, 52, 80
5	Unnominated Seasonal Gas Purchases	-		0.00%	
6	Storage Withdrawal	143	$ 2.4825	0.01%	Sch8A, lns 9, 37, 65
7	Total Purchases	2,366,820		100.00%	
8	Wholesale Sales	(171,465)			Sch8A, lns 22,50,78
9	Third Party	93,787			Sch8A, lns 23, 51, 79
10	Imbalance	13,128			Sch8A, lns 19, 47, 75
11	Fuel Retention	-			Sch8A, lns 15, 43, 71
12	MGT Cash Out Imbalance	(7,424)			Sch8A, lns 25, 53, 81
13	Unnominated Seasonal Gas Payback	-			
14	NNS Injection Loss	(1,525)			Sch8A, lns 26, 54, 82
15	Exelon Cash Out Imbalance	-			Sch8A, lns 27, 55, 83
16	Storage Injection	(505,946)	$ 2.2724		Sch8A, lns 8, 36, 64
17	Net Purchases	1,787,375			
	July 2023	Volumes in Dths	Commodity Cost per Dth	% of Total	
18	Intraday Purchases	66,000	$ 2.3092	2.97%	Sch8B, lns 14, 42, 70
19	Index Purchases	1,546,466	$ 2.2931	69.48%	Sch8B, lns 1,2,3,4,7,11,12,13,29,30,31,32,35,39,40,41,57,58,59,60,63,67,68,69
20	Swing Gas	552,246	$ 1.6657	24.82%	Sch8B, lns 16, 44, 72
21	Boil off/Peaking Purchases	55,196	$ 2.6030	2.48%	Sch8B, lns 24, 52, 80
22	Unnominated Seasonal Gas Purchases	-		0.00%	
23	Storage Withdrawal	5,472	$ 2.6542	0.25%	Sch8B, lns 9, 37, 65
24	Total Purchases	2,225,380		100.00%	
25	Wholesale Sales	(509,558)			Sch8B, lns 22,50,78
26	Third Party	81,130			Sch8B, lns 23, 51, 79
27	Imbalance	(2,558)			Sch8B, lns 19, 47, 75
28	Fuel Retention	-			Sch8B, lns 15, 43, 71
29	MGT Cash Out Imbalance	(1,636)			Sch8B, lns 25, 53, 81
30	Unnominated Seasonal Gas Payback	-			
31	NNS Injection Loss	(705)			Sch8B, lns 26, 54, 82
32	Exelon Cash Out Imbalance	-			Sch8B, lns 27, 55, 83
33	Storage Injection	(309,771)	$ 2.6559		Sch8B, lns 8, 36, 64
34	Net Purchases	1,482,282			
	August 2023	Volumes in Dths	Commodity Cost per Dth	% of Total	
35	Intraday Purchases	(162,910)	$ 1.1999	-8.27%	Sch8C, lns 14, 42, 70
36	Index Purchases	1,629,825	$ 2.0859	82.71%	Sch8C, lns 1,2,3,4,7,11,12,13,29,30,31,32,35,39,40,41,57,58,59,60,63,67,68,69
37	Swing Gas	449,638	$ 1.4022	22.82%	Sch8C, lns 16, 44, 72
38	Boil off/Peaking Purchases	47,937	$ 2.4920	2.43%	Sch8C, lns 24, 52, 80
39	Unnominated Seasonal Gas Purchases	-		0.00%	
40	Storage Withdrawal	6,143	$ 2.5523	0.31%	Sch8C, lns 9, 37, 65
41	Total Purchases	1,970,633		100.00%	
42	Wholesale Sales	(277,700)			Sch8C, lns 22,50,78
43	Third Party	24,150			Sch8C, lns 23, 51, 79
44	Imbalance	(10,406)			Sch8C, lns 19, 47, 75
45	Fuel Retention	-			Sch8C, lns 15, 43, 71
46	MGT Cash Out Imbalance	(608)			Sch8C, lns 25, 53, 81
47	Unnominated Seasonal Gas Payback				
48	NNS Injection Loss	(236)			Sch8C, lns 26, 54, 82
49	Exelon Cash Out Imbalance	-			Sch8C, lns 27, 55, 83
50	Storage Injection	(184,453)	$ 2.5456		Sch8C, lns 8, 36, 64
51	Net Purchases	1,521,380			

Citizens Gas
Calculation of the Average Accrual Pipeline Rate
Non-pipeline Supplies, Storage Injection, and Company Usage

Line No.	Description	June 2023 Dth	June 2023 Rate	June 2023 Amount	July 2023 Dth	July 2023 Rate	July 2023 Amount	August 2023 Dth	August 2023 Rate	August 2023 Amount
1	Panhandle Eastern Pipeline - Demand	31,643	$ 12.2986	$ 389,164	31,643	$ 12.3764	$ 391,628	31,643	$ 12.3764	$ 391,628
2	MGT Pipeline - Demand	900,000	0.0816	73,455	930,000	0.0790	73,455	930,000	0.0790	73,455
3	Indiana Municipal Gas Purchasing Authority - Demand	-	-	-	-	-	-	-	-	-
4	Texas Gas Transmission - Nominated Demand	942,690	0.3798	357,995	974,113	0.4087	398,128	974,113	0.4054	394,918
5	Texas Gas Transmission - Unnominated Demand	-	-	-	-	-	-	-	-	-
6	Texas Gas Transmission - Unnominated Injections	(505,946)	0.4053	(205,060)	(309,771)	0.5178	(160,399)	(184,453)	0.4983	(91,913)
7	Texas Gas Transmission - Unnominated Withdrawal	143	0.4056	58	5,472	0.5177	2,833	6,143	0.4983	3,061
8	Rockies express - Delivered Supply - (BP REX)	-	-	-	-	-	-	-	-	-
9	Rockies Express - EAST (Demand)	20,000	16.7292	334,583	20,000	16.7292	334,583	20,000	16.7292	334,583
10	TGT-PEPL-MGT-REX- Swing Gas (Demand)	-	-	-	-	-	-	-	-	-
11	Utilization Fee	-	-	(203,570)	-	-	(203,570)	-	-	(203,570)
12	Panhandle Eastern/MGT Pipeline/Rockies Express East- Commodity	1,145,970	1.6349	1,873,511	617,985	2.2226	1,373,558	701,344	1.9357	1,357,600
13	Indiana Municipal Gas Purchasing Authority - Commodity	-	-	-	-	-	-	-	-	-
14	Indiana Municipal Gas Purchasing Authority - Prepay Commodity	-	-	-	-	-	-	-	-	-
15	Texas Gas Transmission - Commodity	308,760	(0.4449)	(137,369)	308,760	0.2200	67,917	308,760	(0.0712)	(21,993)
16	Texas Gas Transmission - Unnominated Injection - Commodity	(505,946)	2.2703	(1,148,649)	(309,771)	2.6543	(822,225)	(184,453)	2.5600	(472,200)
17	Texas Gas Transmission - Unnominated Withdrawal - Commodity	143	2.2727	325	5,472	2.6542	14,524	6,143	2.5600	15,726
18	Rockies Express - Delivered Supply - (BP PEAK B)	299,730	1.9753	592,050	309,721	2.3977	742,605	309,721	2.2866	708,195
19	Rockies Express - Delivered Supply - (BP PEAK A)	300,000	1.8460	553,800	310,000	2.2680	703,080	310,000	2.1570	668,670
20	Intra-DayPurchases	103,200	1.8423	190,125	66,000	2.3092	152,405	(162,910)	1.1999	(195,479)
21	TGT-PEPL-MGT-REX- Swing Gas (Commodity)	148,322	1.9396	287,692	552,246	1.6657	919,893	449,638	1.4022	630,472
22	Hedging Transaction Cost	-	-	1,148,859	-	-	989,134	-	-	1,268,858
23	Imbalance	13,128	1.8591	24,406	(2,558)	2.2123	(5,659)	(10,406)	2.1586	(22,462)
24	Wholesale Sales	(171,465)	2.0725	(355,358)	(509,558)	2.2539	(1,148,508)	(277,700)	2.2705	(630,530)
25	Third Party Supplier Balancing Gas Costs	93,787		175,014	81,130		133,384	24,150		13,143
26	Boil-off / Peaking purchase	60,695	2.1810	132,376	55,196	2.6030	143,675	47,937	2.4920	119,459
27	MGT Cash Out Imbalance	-	-	-	-	-	-	-	-	-
28	Fuel Retention Volumes	-	-		-	-		-	-	-
29	NSS Injection fuel loss	(1,525)		-	(705)			(236)		-
30	Exelon Cash Out Imbalance	-	-	-	-	-	-	-	-	-
31	Current Pipeline Rate Per Dth	1,794,799	$2.2751	$ 4,083,407	1,483,918	$2.7633	$ 4,100,441	1,521,988	$2.8526	$ 4,341,621
32	Current Commodity Rate Per Dth	1,794,799	$1.8591	$3,336,782	1,483,918	$2.1994	$3,263,783	1,521,988	$2.2598	3,439,459

Lines 4 & 16 - includes TGT Unnom. Storage Refill Adjustment

Citizens Gas
Calculation of the Average Actual Pipeline Rate
Non-pipeline Supplies, Storage Injection, and Company Usage

Line No.	Description	May 2023 Dth	May 2023 Rate	May 2023 Amount	June 2023 Dth	June 2023 Rate	June 2023 Amount	July 2023 Dth	July 2023 Rate	July 2023 Amount
1	Panhandle Eastern Pipeline - Demand	31,643	$ 12.3396	$ 390,461	31,643	$ 12.2878	$ 388,823	31,643	$ 12.3635	$ 391,219
2	MGT Pipeline - Demand	930,000	0.0790	73,455	900,000	0.0816	73,455	930,000	0.0790	73,455
3	Indiana Municipal Gas Purchasing Authority - Demand	-	-	-	-	-	-	-	-	-
4	Texas Gas Transmission - Nominated Demand	974,113	0.3543	345,128	942,690	0.3798	357,995	974,113	0.4087	398,128
5	Texas Gas Transmission - Unnominated Demand	-	-	-	-	-	-	-	-	-
6	Texas Gas Transmission - Unnominated Injections	(382,096)	0.3554	(135,797)	(505,946)	0.4054	(205,111)	(309,771)	0.5250	(162,630)
7	Texas Gas Transmission - Unnominated Withdrawal	10,869	0.3554	3,863	143	0.4056	58	5,472	0.5250	2,873
8	Rockies express - Delivered Supply - (BP REX)	-	-	-	-	-	-	-	-	-
9	Rockies Express - EAST- (Demand)	20,000	16.7292	334,583	20,000	16.7292	334,583	20,000	16.6988	333,976
10	TGT-PEPL-MGT-REX- Swing Gas (Demand)	-	-	-	-	-	-	-	-	-
11	Utilization Fee	-	-	(203,570)	-	-	(203,570)	-	-	(203,570)
12	Panhandle Eastern/MGT Pipeline/Rockies Express East- Commodity	1,165,941	1.8047	2,104,213	1,145,970	1.6349	1,873,511	617,985	2.2226	1,373,558
13	Indiana Municipal Gas Purchasing Authority - Commodity	-	-	-	-	-	-	-	-	-
14	Indiana Municipal Gas Purchasing Authority - Prepay Commodity	-	-	-	-	-	-	-	-	-
15	Texas Gas Transmission - Commodity	308,760	1.9030	587,576	308,760	(0.4449)	(137,369)	308,760	0.2200	67,917
16	Texas Gas Transmission - Unnominated Injection - Commodity	(382,096)	2.5964	(992,074)	(505,946)	2.2713	(1,149,155)	(309,771)	2.6457	(819,561)
17	Texas Gas Transmission - Unnominated Withdrawal - Commodity	10,869	2.5964	28,220	143	2.2727	325	5,472	2.6457	14,477
18	Rockies Express - Delivered Supply - (BP PEAK B)	309,721	1.9112	591,945	299,730	1.9753	592,050	309,721	2.3977	742,605
19	Rockies Express - Delivered Supply - (BP PEAK A)	310,000	1.7820	552,420	300,000	1.8460	553,800	310,000	2.2680	703,080
20	Intra-DayPurchases	271,300	2.0133	546,208	103,200	1.8423	190,125	66,000	2.3092	152,405
21	TGT-PEPL-MGT-REX- Swing Gas (Commodity)	224,247	1.9451	436,177	148,322	1.9396	287,692	552,246	1.6657	919,893
22	Hedging Transaction Cost	-	-	1,939,880	-	-	1,148,859	-	-	989,134
23	Imbalance	1,772	2.5971	4,602	13,128	1.8589	24,404	(2,558)	2.2048	(5,640)
24	Wholesale Sales	(125,000)	1.7866	(223,323)	(171,465)	2.0725	(355,358)	(509,558)	2.2539	(1,148,508)
25	Third Party Supplier Balancing Gas Costs	139,979		243,573	93,787		175,014	81,130		133,384
26	Boil-off / Peaking purchase	47,262	2.1170	100,054	60,695	2.1810	132,376	55,196	2.6030	143,675
27	MGT Cash Out Imbalance	(7,424)	1.6067	(11,928)	(1,636)	0.8667	(1,418)	(608)	(3.3816)	2,056
28	Fuel Retention Volumes	-	-	-	-	-	-	-	-	-
29	NSS Injection fuel loss	(712)	-	-	(1,525)	-	-	(705)	-	-
30	Exelon Cash Out Imbalance	-	-	-	-	-	-	-	-	-
31	Current Pipeline Rate Per Dth	2,274,619	$2.9524	$ 6,715,666	1,793,163	$2.2759	$ 4,081,089	1,483,310	$2.7654	$ 4,101,926
32	Current Commodity Rate Per Dth	2,274,619	$2.5972	5,907,543	1,793,163	$1.8598	3,334,856	1,483,310	$2.2035	3,268,475

Lines 4 & 16 - includes TGT Unnom. Storage Refill Adjustment

Citizens Gas
PEPL Unnominated Quantities Cost
June 2023

Line No.		A Compres. Fuel-Dth	B Demand Costs	C Volumes	D Storage Rates	E Compres. Fuel	F Total
	Accrual - May, 2023						
	PEPL						
1	Demand Cost		$556,263				$556,263
2	PEPL Injection fuel cost	15,462				45,599	45,599
3	PEPL Injection (Net)			636,441	$0.0020		1,273
4	(100-day Firm) (Midpoint)			649,299	0.0094		6,103
5	PEPL Withdrawal fuel cost	9				38	38
6	PEPL Withdrawal (Midpoint)			462	0.0020		1
7	(100-day Firm) (Net)			460	0.0094		4
8	PEPL - Sub Total		$556,263			$45,637	$609,281
	Actual - May, 2023						
	PEPL						
9	Demand Cost		$565,665				$565,665
10	PEPL Injection fuel cost	15,462				45,650	45,650
11	PEPL Injection (Net)			636,441	0.0020		1,273
12	(100-day Firm) (Midpoint)			649,299	0.0094		6,103
13	PEPL Withdrawal fuel cost	9				38	38
14	PEPL Withdrawal (Midpoint)			462	0.0020		1
15	(100-day Firm) (Net)			460	0.0094		4
16	PEPL - Sub Total		$565,665			$45,688	$618,734
	Accrual - June, 2023						
	PEPL						
17	Demand Cost		$543,089				$543,089
18	PEPL Injection fuel cost	18,926				43,059	43,059
19	PEPL Injection (Net)			778,915	0.0020		1,558
20	(100-day Firm) (Midpoint)			794,649	0.0094		7,470
21	PEPL Withdrawal fuel cost	-				-	-
22	PEPL Withdrawal (Midpoint)			-	0.0020		-
23	(100-day Firm) (Net)			-	0.0094		-
24	PEPL - Sub Total		$543,089			$43,059	$595,176
25	Total (line 24 + line 16 - line 8)		$552,491			$43,110	$604,629
26	PEPL - Balancing Costs (ln 25 * 9%)						$54,417
27	PEPL - Retail Costs (ln 25 * 91%)						$550,212

Citizens Gas
PEPL Unnominated Quantities Cost
July 2023

Line No.		A Compres. Fuel-Dth	B Demand Costs	C Volumes	D Storage Rates	E Compres. Fuel	F Total
	Accrual - June, 2023						
	PEPL						
1	Demand Cost		$543,089				$543,089
2	PEPL Injection fuel cost	18,926				43,059	43,059
3	PEPL Injection (Net)			778,915	$0.0020		1,558
4	(100-day Firm) (Midpoint)			794,649	0.0094		7,470
5	PEPL Withdrawal fuel cost	-				-	-
6	PEPL Withdrawal (Midpoint)			-	0.0020		-
7	(100-day Firm) (Net)			-	0.0094		-
8	PEPL - Sub Total		$543,089			$43,059	$595,176
	Actual - June, 2023						
	PEPL						
9	Demand Cost		$543,508				$543,508
10	PEPL Injection fuel cost	18,926				43,074	43,074
11	PEPL Injection (Net)			778,915	0.0020		1,558
12	(100-day Firm) (Midpoint)			794,649	0.0094		7,470
13	PEPL Withdrawal fuel cost	-				-	-
14	PEPL Withdrawal (Midpoint)			-	0.0020		-
15	(100-day Firm) (Net)			-	0.0094		-
16	PEPL - Sub Total		$543,508			$43,074	$595,610
	Accrual - July, 2023						
	PEPL						
17	Demand Cost		$556,263				$556,263
18	PEPL Injection fuel cost	16,584				45,827	45,827
19	PEPL Injection (Net)			682,508	0.0020		1,365
20	(100-day Firm) (Midpoint)			696,295	0.0094		6,545
21	PEPL Withdrawal fuel cost	-				-	-
22	PEPL Withdrawal (Midpoint)			-	0.0020		-
23	(100-day Firm) (Net)			-	0.0094		-
24	PEPL - Sub Total		$556,263			$45,827	$610,000
25	Total (line 24+ line 16 - line 8)		$556,682			$45,842	$610,434
26	PEPL Balancing Costs (ln 25 * 9%)						$54,939
27	PEPL Retail Costs (ln 25 * 91%)						$555,495

Citizens Gas
PEPL Unnominated Quantities Cost
August 2023

Line No.		A Compres. Fuel-Dth	B Demand Costs	C Volumes	D Storage Rates	E Compres. Fuel	F Total
	Accrual - July, 2023						
	PEPL						
1	Demand Cost		$556,263				$556,263
2	PEPL Injection Fuel Cost	16,584				45,827	45,827
3	PEPL Injection (Net)			682,508	$0.0020		1,365
4	(100-day Firm) (Midpoint)			696,295	0.0094		6,545
5	PEPL Withdrawal Fuel Cost	-				-	-
6	PEPL Withdrawal (Midpoint)			-	0.0020		-
7	(100-day Firm) (Net)			-	0.0094		-
8	PEPL Total		$556,263			$45,827	$610,000
	Actual - July, 2023						
	PEPL						
9	Demand Cost		$558,970				$558,970
10	PEPL Injection Fuel Cost	16,584				45,861	45,861
11	PEPL Injection (Net)			682,510	$0.0020		1,365
12	(100-day Firm) (Midpoint)			696,297	0.0094		6,545
13	PEPL Withdrawal Fuel Cost	-				-	-
14	PEPL Withdrawal (Midpoint)			-	0.0020		-
15	(100-day Firm) (Net)			-	0.0094		-
16	PEPL Total		$558,970			$45,861	$612,741
	Accrual - August, 2023						
	PEPL						
17	Demand Cost		$556,263				$556,263
18	PEPL Injection Fuel Cost	9,785				27,913	27,913
19	PEPL Injection (Net)			402,751	$0.0020		806
20	(100-day Firm) (Midpoint)			410,886	0.0094		3,862
21	PEPL Withdrawal fuel cost	73				256	256
22	PEPL Withdrawal (Midpoint)			3,888	0.0020		8
23	(100-day Firm) (Net)			3,872	0.0094		36
24	PEPL Total		$556,263			$28,169	$589,144
25	Total (line 24 + line 16 - line 8)		$558,970			$28,203	$591,885
26	PEPL Balancing Costs (ln 25 * 9%)						$53,270
27	PEPL Retail Costs (ln 25 * 91%)						$538,615

Citizens Gas
Cost of Gas Injections and Withdrawals
For the period June 1, 2023 - August 31, 2023

		A	B	C	D	E	F	G	H	I
		Estimated Change		Cost of Gas						
				Injections		Withdrawals		Net		
Line No.		Injections Dth	Withdrawals Dth	Demand	Commodity	Demand	Commodity	Demand	Commodity	Total
	June 2023									
1	UGS	474,560	41,992	$197,744	$884,087	$16,961	$153,367	($180,783)	($730,720)	($911,503)
2	PEPL	797,841	-	332,228	1,485,091	-	-	(332,228)	(1,485,091)	(1,817,319)
3	Subtotal	1,272,401	41,992	$529,972	$2,369,178	$16,961	$153,367	($513,011)	($2,215,811)	($2,728,822)
	July 2023									
4	UGS	253,106	47,521	$142,774	$557,014	$19,265	$163,064	($123,509)	($393,950)	($517,459)
5	PEPL	699,092	-	394,297	1,538,142	-	-	(394,297)	(1,538,142)	(1,932,439)
6	Subtotal	952,198	47,521	537,071	2,095,156	19,265	163,064	(517,806)	(1,932,092)	(2,449,898)
	August 2023									
7	UGS	681,750	9,323	$403,634	$1,541,657	$3,870	$31,277	($399,764)	($1,510,380)	($1,910,144)
8	PEPL	412,538	3,872	243,154	935,120	1,627	11,928	(241,527)	(923,192)	(1,164,719)
9	Subtotal	1,094,288	13,195	646,788	2,476,777	5,497	43,205	(641,291)	(2,433,572)	(3,074,863)
10	Grand Total	3,318,887	102,708	$1,713,831	$6,941,111	$41,723	$359,636	$ (1,672,108)	$ (6,581,475)	$ (8,253,583)

Citizens Gas
Demand Allocation of Injections and Withdrawals
From PEPL
For Three Months Ending August 31, 2023

		A	B	C	D	E	F
Line No.		Volume DTH	Demand Cost	Commodity Cost	Total Cost	Total $/DTH	Commodity $/DTH
1	Beginning balance @ June 2023	3,318,610	$1,300,270	$11,771,217	$13,071,487	$3.9388	$3.5470
2	Less: Net W/D @ avg. unit cost						
3	Prior mo. accrual reversal	460	184	1,736	1,920	4.1737	3.7731
4	Prior mo. actual	(460)	(184)	(1,736)	(1,920)	4.1737	3.7731
5	Current mo. accrual	-	-	-	-	-	-
6	Add: Gross Injections						
7	Prior mo. accrual reversal	(651,903)	(231,230)	(1,691,297)	(1,922,527)	2.9491	2.5944
8	Prior mo. actual	651,903	231,556	1,693,122	1,924,678	2.9524	2.5972
9	Current mo. accrual	797,841	331,902	1,483,266	1,815,168	2.2751	1.8591
10	Less: Compressor Fuel						
11	Prior mo. accrual reversal - W/D	9	4	34	38	4.1737	3.7731
12	Prior mo. accrual reversal - Injections	15,462	5,484	40,115	45,599	2.9491	2.5944
13	Prior mo. Actual - W/D	(9)	(4)	(34)	(38)	4.1737	3.7731
14	Prior mo. Actual - Injections	(15,462)	(5,492)	(40,158)	(45,650)	2.9524	2.5972
15	Current mo. Accrual -Inj	(18,926)	(7,874)	(35,185)	(43,059)	2.2751	1.8591
16	Current mo. Accrual-W/D	-	-	-	-	-	-
17	Beginning balance @ July 2023	4,097,525	1,624,616	13,221,080	14,845,696	3.6231	3.2266
18	Less: Net W/D @ avg. unit cost						
19	Prior mo. accrual reversal	-	-	-	-	-	-
20	Prior mo. actual	-	-	-	-	-	-
21	Current mo. accrual	-	-	-	-	-	-
22	Add: Gross Injections						
23	Prior mo. accrual reversal	(797,841)	(331,902)	(1,483,266)	(1,815,168)	2.2751	1.8591
24	Prior mo. actual	797,841	331,981	1,483,825	1,815,806	2.2759	1.8598
25	Current mo. accrual	699,092	394,218	1,537,583	1,931,801	2.7633	2.1994
26	Less: Compressor Fuel						
27	Prior mo. accrual reversal - W/D	-	-	-	-	-	-
28	Prior mo. accrual reversal - Inj	18,926	7,874	35,185	43,059	2.2751	1.8591
29	Prior mo. Actual - W/D	-	-	-	-	-	-
30	Prior mo. Actual - Injections	(18,926)	(7,875)	(35,199)	(43,074)	2.2759	1.8598
31	Current mo. accrual - Inj	(16,584)	(9,352)	(36,475)	(45,827)	2.7633	2.1994
32	Current mo. Accrual-W/D	-	-	-	-	-	-
33	Beginning balance @ August 2023	4,780,033	2,009,560	14,722,733	16,732,293	3.5005	3.0800
34	Less: Net W/D @ avg. unit cost						
35	Prior mo. accrual reversal	-	-	-	-	-	-
36	Prior mo. actual	-	-	-	-	-	-
37	Current mo. accrual	(3,872)	(1,627)	(11,928)	(13,555)	3.5008	3.0806
38	Add: Gross Injections						
39	Prior mo. accrual reversal	(699,092)	(394,218)	(1,537,583)	(1,931,801)	2.7633	2.1994
40	Prior mo. actual	699,094	392,821	1,540,454	1,933,275	2.7654	2.2035
41	Current mo. Accrual	412,536	244,551	932,249	1,176,800	2.8526	2.2598
42	Less: Compressor Fuel						
43	Prior mo. accrual reversal - W/D	-	-	-	-	-	-
44	Prior mo. accrual reversal - Inj	16,584	9,352	36,475	45,827	2.7633	2.1994
45	Prior mo. Actual - W/D	-	-	-	-	-	-
46	Prior mo. Actual - Injections	(16,584)	(9,318)	(36,543)	(45,861)	2.7654	2.2035
47	Current mo. accrual -Inj	(9,785)	(5,801)	(22,112)	(27,913)	2.8526	2.2598
48	Current mo. Accrual-W/D	(73)	(31)	(225)	(256)	3.5008	3.0806
49	Ending balance @ August 31, 2023	5,178,841	2,245,289	15,623,520	17,868,809	$3.4503	$3.0168

Citizens Gas
Demand Allocation of Injections and Withdrawals
From UGS
For Three Months Ending August 31, 2023

		A	B	C	D	E	F
Line No.		Volume	Demand Cost	Commodity Cost	Total Cost	Total $/Unit	Commodity $/Unit
1	Beginning balance @ June 2023	3,419,468	$1,380,785	$12,487,060	$13,867,845	$4.0556	$3.6518
2	Add: Gross Injections						
3	Less: Prior mo. accrual	(654,719)	(232,229)	(1,698,603)	(1,930,832)	2.9491	2.5944
4	Add: Prior mo. actual	654,719	232,556	1,700,436	1,932,992	2.9524	2.5972
5	Add: Current mo. accrual	474,560	197,417	882,254	1,079,671	2.2751	1.8591
6	Less: Net Withdrawals						
7	Prior mo. accrual reversal	1,995	829	7,785	8,614	4.3176	3.9021
8	Prior mo. Actual	(1,995)	(829)	(7,785)	(8,614)	4.3176	3.9021
9	Current mo. accrual	(41,992)	(16,961)	(153,367)	(170,328)	4.0562	3.6523
10	Less: Blowoff						
11	Current mo. Blowoff	(1,059)	(428)	(3,868)	(4,296)	4.0562	3.6523
12	Beginning balance @ July 2023	3,850,977	1,561,140	13,213,912	14,775,052	3.8367	3.4313
13	Add: Gross Injections						
14	Less: Prior mo. accrual	(474,560)	(197,417)	(882,254)	(1,079,671)	2.2751	1.8591
15	Add: Prior mo. actual	474,560	197,464	882,587	1,080,051	2.2759	1.8598
16	Add: Current mo. accrual	253,106	142,727	556,681	699,408	2.7633	2.1994
17	Less: Net Withdrawals						
18	Prior mo. accrual reversal	41,992	16,961	153,367	170,328	4.0562	3.6523
19	Prior mo. actual	(41,992)	(16,961)	(153,367)	(170,328)	4.0562	3.6523
20	Current mo. accrual	(47,521)	(19,265)	(163,064)	(182,329)	3.8368	3.4314
21	Less: Blowoff						
22	Current mo. Blowoff	(615)	(250)	(2,110)	(2,360)	3.8368	3.4314
23	Beginning balance @ August 2023	4,055,947	1,684,399	13,605,752	15,290,151	3.7698	3.3545
24	Add: Injections						
25	Less: Prior mo. accrual	(253,106)	(142,727)	(556,681)	(699,408)	2.7633	2.1994
26	Prior mo. actual	253,106	142,220	557,719	699,939	2.7654	2.2035
27	Current mo. accrual	681,750	404,141	1,540,619	1,944,760	2.8526	2.2598
28	Less: Withdrawals						
29	Prior mo. accrual reversal	47,521	19,265	163,064	182,329	3.8368	3.4314
30	Prior mo. actual	(47,521)	(19,265)	(163,064)	(182,329)	3.8368	3.4314
31	Current mo. Accrual	(9,323)	(3,870)	(31,277)	(35,147)	3.7699	3.3548
32	Less: Blowoff						
33	Current mo. Blowoff	(3,086)	(1,281)	(10,353)	(11,634)	3.7699	3.3548
34	Ending balance @ August 31, 2023	4,725,288	2,082,882	15,105,779	17,188,661	$3.6376	$3.1968

Citizens Gas
Determination of "Unaccounted For" Percentage and Manufacturing / Steam Division Costs
For Three Months Ending August 31, 2023

Line No.		A June 2023	B July 2023	C August 2023	D Total
1	Volume of pipeline gas purchases - Dths (See Schedule 8)	1,787,375	1,482,282	1,521,380	4,791,037
2	Gas (injected into) withdrawn from storage (See Schedule 10)	(1,230,409)	(904,677)	(1,081,093)	(3,216,179)
3	Transported gas received	1,254,812	1,145,133	1,101,813	3,501,758
4	Transported gas (injected into) withdrawn from storage	0	0	0	0
5	Reverse transport imbalance already on Sch 8	(93,787)	(81,130)	(24,150)	(199,067)
6	Total volume supplied	1,717,991	1,641,608	1,517,950	4,877,549
7	Less: Gas Division usage	(2,358)	(1,656)	(1,371)	(5,385)
8	Total volume available for sale	1,715,633	1,639,952	1,516,579	4,872,164
9	Retail Volume of gas sold - Dths (Schedule 6, Page 3, ln 24)	612,919	661,365	633,940	1,908,224
10	Total Transport Usage (Sch 6, Page 3, ln 25 + ln 26)	1,171,566	1,053,060	1,075,917	3,300,543
11	"Unaccounted for" gas (ln 8 - ln 9 - ln 10)	(68,852)	(74,473)	(193,278)	(336,603)
12	Percentage of "unaccounted for" gas (line 11 / line 8)	-4.01%	-4.54%	-12.74%	-6.91%

Citizens Gas
Annual True-Up for Cost of Unaccounted for (UAF) Gas
For the Period of September 2022 To August 2023

		A	B	C	D	E
		Volume of Gas Available (Dth)	Volume of Gas Delivered To Customers (Dth)	Volume of UAF Gas (Dth)	Percent of UAF Gas	Actual Commodity Costs
		Sch 11, ln 8	Sch 11, ln 9 & ln 10	col. A - col. B	col. C / col. A	Sch 7 pg 1, ln 5 - ln 3
1	September '22	1,737,926	1,477,110	260,816	15.01%	$3,762,074
2	October	2,916,730	2,700,733	215,997	7.41%	6,394,664
3	November	4,860,389	4,815,083	45,306	0.93%	16,115,783
4	December	7,335,142	6,747,653	587,489	8.01%	26,166,388
5	January '23	6,968,722	6,877,533	91,189	1.31%	19,566,495
6	February	5,558,095	5,385,938	172,157	3.10%	11,593,699
7	March	5,649,403	5,577,026	72,377	1.28%	15,640,250
8	April	3,384,282	3,302,858	81,424	2.41%	5,448,777
9	May	2,120,881	2,168,036	(47,155)	-2.22%	2,543,010
10	June	1,715,633	1,784,485	(68,852)	-4.01%	1,108,008
11	July	1,639,952	1,714,425	(74,473)	-4.54%	1,329,765
12	August	1,516,579	1,709,857	(193,278)	-12.74%	1,010,579
13	12-month total	45,403,734	44,260,737	1,142,997	2.5174%	$110,679,492

14	Actual UAF % - 12 Months Ended (ln. 13, col. D)			2.5174%
15	Maximum UAF % collected in GCA rate -			1.3600%
16	UAF % Adjustment (0 if actual < maximum)	1/		1.1574%
17	Actual Commodity Costs (ln. 13, col. E)		$	110,679,492
18	UAF Refund - (ln. 16 X ln. 17)		$	1,281,004

1/ If actual UAF % is less than the maximum UAF % no adjustment is necessary.
If actual UAF % exceeds the maximum UAF %, then a refund is necessary for the difference between maximum UAF% and the actual UAF%.

CITIZENS GAS

Initiation of Refund

Line No.	Refunds	
1	Supplier:	
2	Date received:	
3	Amount of refund:	$0
4	Reason for Refund:	
5	Docket Number:	
6	Total to be refunded	$0

Distribution of Refunds to GCA Quarters

Line No.	Quarter	A Sales % (All GCA Classes)		B Refund (line 6 * column A)
7	Dec., 2023 - Feb., 2024	53.1918%	(Sch. 2B, ln 18)	$0
8	Mar., 2024 - May., 2024	26.9854%	(Sch. 2B, ln 19)	$0
9	Jun., 2024 - Aug., 2024	6.1119%	(Sch. 2B, ln 20)	$0
10	Sep., 2024 - Nov., 2024	13.7109%	(Sch. 2B, ln 21)	$0
11	Total			$0

Calculation of Refund to be Returned in this GCA

Line No.		
12	Refund from Cause No. 37399-GCA 157	$0
13	Refund from Cause No. 37399-GCA 158	0
14	Refund from Cause No. 37399-GCA 159	0
15	Refund from this Cause (line 7)	0
16	Total to be refunded in this Cause (Sum of lines 12 through 15)	$0

Citizens Gas
Allocation of Gas Supply Variance

Line No.		A Gas Rate No. D1	B Gas Rate No. D2	C Gas Rate No. D3/ No. D7	D Gas Rate No. D4	E Gas Rate No. D5	F Gas Cost Variances
	Calculation of Total Gas Cost Variances						
1	Jun., 2023 Total Gas Supply Variance (Sch 6A, pg. 1, ln 15)	(4,946)	(330,324)	(52,422)	(375,960)	0	(763,652)
2	Jul., 2023 Total Gas Supply Variance (Sch 6B, pg. 1, ln 15)	(6,625)	(586,747)	(67,991)	(502,677)	0	(1,164,040)
3	Aug., 2023 Total Gas Supply Variance (Sch 6C, pg. 1, ln 15)	(6,884)	(652,455)	(99,487)	(575,460)	0	(1,334,286)
4	Total Net Write Off Gas Cost Variance (over)/under recover (Sch 12C, ln19)	(138)	(26,512)	(12)	(7,155)	45	(33,772)
5	Annual Unaccounted for over-recovery (Sch 11a, ln 18, col. D * Sch 2B, ln 22)	(5,437)	(879,736)	(35,075)	(360,756)	0	(1,281,004)
6	Sub-Total Gas Supply Variance (over)/underrecovery (ln 1 + ln 2 + ln 3 + ln 4 + ln 5)	($24,030)	($2,475,774)	($254,987)	($1,822,008)	$45	(4,576,754)
	Distribution of variances to quarters by rate class						
7	First quarter Total Gas Supply Variance (ln 6 * Sch 2B, ln 18)	($11,945)	($1,353,778)	($83,884)	($939,901)	$0	($2,389,508)
8	Second quarter Total Gas Supply Variance (ln 6 * Sch 2B, ln 19)	(6,335)	(675,815)	(56,794)	(486,347)	0	(1,225,291)
9	Third quarter Total Gas Supply Variance (ln 6 * Sch 2B, ln 20)	(2,301)	(123,563)	(51,005)	(135,605)	0	(312,474)
10	Fourth quarter Total Gas Supply Variance (ln 6 * Sch 2B, ln 21)	(3,449)	(322,618)	(63,304)	(260,155)	0	(649,526)
	Calculation of variances for this Cause						
11	Cause No. 37399 - GCA 157 Total Gas Supply Variance (Sch 12B pg 1, ln 10)	10,077	1,133,958	150,603	565,648	0	1,860,286
12	Cause No. 37399 - GCA 158 Total Gas Supply Variance (Sch 12B pg 1, ln 9)	(3,868)	(513,059)	(40,802)	(305,705)	0	(863,434)
13	Cause No. 37399 - GCA 159 Total Gas Supply Variance (Sch 12B pg 1, ln 8)	3,561	665,125	(2,472)	277,520	0	943,734
14	This Cause Total Gas Supply Variance (line 7)	(11,945)	(1,353,778)	(83,884)	(939,901)	0	($2,389,508)
15	Total Gas Supply Variance to be included in GCA (Over)/Underrecovery (ln 11 + ln 12 + ln 13 + ln 14)	($2,175)	($67,754)	$23,445	($402,438)	$0	($448,922)

Citizens Gas
Allocation of Balancing Demand Cost Variance

Line No.		A Gas Rate No. D1	B Gas Rate No. D2	C Gas Rate No. D3 / No. D7	D Gas Rate No. D4	E Gas Rate No. D5	F Gas Rate No. D9	G Balancing Demand Cost Variance
	Calculation of Total Balancing Demand Cost Variances							
1	Jun., 2023 Total Balancing Demand Cost Variance (Sch 6A, pg. 2, ln 23)	($126)	($9,069)	($5,529)	($9,220)	($1,990)	$5,266	($20,668)
2	Jul., 2023 Total Balancing Demand Cost Variance (Sch 6B, pg. 2, ln 23)	($119)	($9,702)	($5,498)	($9,113)	($1,946)	$6,099	($20,279)
3	Aug., 2023 Total Balancing Demand Cost Variance (Sch 6C, pg. 2, ln 23)	($105)	($9,022)	($5,886)	($9,751)	($2,660)	$5,759	($21,665)
4	Balancing Demand Cost Variance (Line 1 + Line 2 + Line 3)	($350)	($27,793)	($16,913)	($28,084)	($6,596)	$17,124	($62,612)
	Distribution of variances to quarters by rate class							
5	First quarter Total Balancing Demand Cost Variance (ln 4 * Sch 2A, ln 18)	($174)	($15,197)	($4,800)	($13,964)	($2,237)	$4,436	($31,936)
6	Second quarter Total Balancing Demand Cost Variance (ln 4 * Sch 2A, ln 19)	($92)	($7,587)	($4,074)	($7,134)	($1,606)	$4,608	($15,885)
7	Third quarter Total Balancing Demand Cost Variance (ln 4 * Sch 2A, ln 20)	($34)	($1,387)	($3,821)	($2,180)	($1,204)	$4,406	($4,220)
8	Fourth quarter Total Balancing Demand Cost Variance (ln 4 * Sch 2A, ln 21)	($50)	($3,622)	($4,218)	($4,806)	($1,549)	$3,674	($10,571)
	Calculation of variances for this Cause							
9	Cause No. 37399 - GCA 157 Total Balancing Demand Cost Variance (Sch 12B, pg. 2, ln 8)	($98)	($16,313)	($1,726)	($11,118)	$1,043	$5,359	($22,853)
10	Cause No. 37399 - GCA 158 Total Balancing Demand Cost Variance (Sch 12B, pg. 2, ln 7)	($39)	($5,957)	($68)	($4,391)	$2,292	$2,455	($5,708)
11	Cause No. 37399 - GCA 159 Total Balancing Demand Cost Variance (Sch 12B, pg. 2, ln 6)	($73)	($9,762)	($553)	($6,828)	$1,270	$1,656	($14,290)
12	This Cause Total Current Balancing Demand Cost Variance (line 5)	($174)	($15,197)	($4,800)	($13,964)	($2,237)	$4,436	($31,936)
13	Total Balancing Demand Cost Variance to be included in GCA (Over)/Underrecovery (ln 9 + ln 10 + ln 11 + ln 12)	($384)	($47,229)	($7,147)	($36,301)	$2,368	$13,906	($74,787)

CITIZENS GAS
SCHEDULE 12C
DETERMINATION OF NET WRITE-OFF GAS COST RECOVERIES

Line No.		A	B	C	D	E	F
	June 2023						
		D1	**D2**	**D3**	**D4**	**D5**	**Total**
1	Actual Retail Sales in Dth (Sch 6A, line 24)	4,873	343,593	57,257	207,196	-	612,919
2	Net Write-Off Gas Cost Component per Dth Cause No. 37399-GCA 158, MPU Sch 1 pg 2, ln 23	$0.0250	$0.0710	$0.0010	$0.0180	$0.0000	
3	Actual Net Write Off Gas Cost Recovery (ln 1 * ln 2)	$122	$24,395	$57	$3,730	$0	$28,304
4	Net Write Off Recovery Allocation Factors Cause No. 43975	0.004201	0.908991	0.002576	0.083537	0.000695	1.000000
5	Recoverable Net-Write Off Gas Costs (Sch 6A, ln 9, Total * 1.10% * ln 4)	$87	$18,903	$54	$1,737	$14	$20,795
6	Net Write Off Gas Cost Variance (over)/under recovery (ln 5 - ln 3)	**($35)**	**($5,492)**	**($3)**	**($1,993)**	**$14**	**($7,509)**
	July 2023						
7	Actual Retail Sales in Dth (Sch 6B, line 24)	4,594	368,541	58,292	229,938	-	661,365
8	Net Write-Off Gas Cost Component per Dth Cause No. 37399-GCA 158, MPU Sch 1 pg 2, ln 23	$0.0340	$0.0870	$0.0010	$0.0200	$0.0000	
9	Actual Net Write Off Gas Cost Recovery (ln 7 * ln 8)	$156	$32,063	$58	$4,599	$0	$36,876
10	Net Write Off Recovery Allocation Factors Cause No. 43975	0.004201	0.908991	0.002576	0.083537	0.000695	1.000000
11	Recoverable Net-Write Off Gas Costs (Sch 6B, ln 9, Total * 1.10% * ln 10)	$102	$22,035	$62	$2,025	$17	$24,241
12	Net Write Off Gas Cost Variance (over)/under recovery (ln 11 - ln 9)	**($54)**	**($10,028)**	**$4**	**($2,574)**	**$17**	**($12,635)**
	August 2023						
13	Actual Retail Sales in Dth (Sch 6C, line 24)	3,992	341,872	64,474	223,602	-	633,940
14	Net Write-Off Gas Cost Component per Dth Cause No. 37399-GCA 158, MPU Sch 1 pg 2, ln 23	$0.0330	$0.0850	$0.0010	$0.0190	$0.0000	
15	Actual Net Write Off Gas Cost Recovery (ln 13 * ln 14)	$132	$29,059	$64	$4,248	$0	$33,503
16	Net Write Off Recovery Allocation Factors Cause No. 43975	0.004201	0.908991	0.002576	0.083537	0.000695	1.000000
17	Recoverable Net-Write Off Gas Costs (Sch 6C, ln 9, Total * 1.10% * ln 16)	$83	$18,067	$51	$1,660	$14	$19,875
18	Net Write Off Gas Cost Variance (over)/under recovery (ln 17 - ln 15)	**($49)**	**($10,992)**	**($13)**	**($2,588)**	**$14**	**($13,628)**
19	Total Net Write Off Gas Cost Variance (over)/under recovery (ln 6 + ln 12 + ln 18)	($138)	($26,512)	($12)	($7,155)	$45	($33,772)